PGX.UN

SUSTAINABLE PERFORMANCE

05

PROGRESS

Annual Report to Unitholders

PROGRESS ENERGY TRUST

	Year ended December 31 ($ millions, except per unit amounts)	2005	2004 (3)	Change
Financial	Petroleum and natural gas revenue	**369.8**	214.7	72 %
	Cash flow (2)	**206.0**	110.5	86 %
	Per unit – diluted	**2.45**	1.87	31 %
	Cash distributions declared (1)	**116.5**	55.7	109 %
	Per unit	**1.68**	0.84	100 %
	Net earnings	**88.9**	44.2	101 %
	Per unit – Basic	**1.29**	0.89	45 %
	– Diluted	**1.27**	0.88	44 %
	Payout ratio			
	Excluding exchangeable shares	**57%**		
	Including exchangeable shares	**69%**		
	Capital expenditures	**107.7**	106.4	1 %
	Working capital deficiency	**22.9**	37.8	(40)%
	Bank debt	**71.3**	133.7	(47)%
	Convertible debentures	**79.4**	–	
	Total debt	**173.6**	171.5	1 %
	Unitholders' equity	**654.6**	614.8	6 %
	Total units outstanding and issuable for exchangeable shares *(thousands)*	**84,784**	82,189	3 %
Operating	Average daily production			
	Natural gas *(mcf/d)*	**82,431**	62,221	32 %
	Crude oil *(bbls/d)*	**2,779**	2,335	19 %
	Natural gas liquids *(bbls/d)*	**1,384**	814	70 %
	Total daily production *(boe/d)*	**17,901**	13,519	32 %
	Reserves – proved plus probable			
	Natural gas *(bcf)*	**280.8**	255.9	10 %
	Crude oil *(mmbbls)*	**7.3**	7.4	(1)%
	Natural gas liquids *(mmbbls)*	**4.8**	4.2	14 %
	Total reserves *(mmboe)*	**58.9**	54.3	9 %
	Wells drilled – net			
	Natural gas	**36.8**	30.5	21 %
	Crude oil	**6.2**	7.0	(11)%
	Success rate *(%)*	**90**	89	

(1) Cash distributions declared in 2004 reflect 6 months of operations as a trust.

(2) Cash flow is a non-GAAP term. Refer to Management's Discussion and Analysis attached.

(3) Certain comparative numbers reflect the retroactive restatement due to changes in accounting policies.

Advisory

Certain information regarding Progress set forth in this document, including Management's assessment of Progress' future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

$1.68

per unit distributions in 2005

42%

total unitholder return in 2005

Company Profile

Progress Energy Trust ("Progress" or the "Trust") is a natural gas weighted energy trust based in Calgary, Alberta. Progress seeks to generate a sustainable stream of cash distributions by targeting paced growth in production and reserves per unit. Progress is characterized by its stable production base; an extensive inventory of drilling locations; a large undeveloped land base; a strong balance sheet, and; a history of generating a steady stream of cash distributions.

Approximately 85 percent of the Trust's asset base is focused in the Deep Basin region of northwest Alberta and the Foothills and Plains regions of northeast British Columbia. The Trust leverages the technical strengths of its professionals to generate new play concepts which will further extend the Trust's drilling inventory and opportunity set.

Progress trades on the Toronto Stock Exchange under the symbol PGX.UN. Exchangeable shares of Progress trade under the symbol PGE and convertible debentures trade under the symbol PGX.DB.

Progress Energy Trust

Letter to Unitholders

We formed Progress Energy Trust, **creating a trust with high-quality assets capable of sustaining production and reserves per unit, and staffed by technically strong professionals capable of creating value.**

In 2005, Progress Energy Trust had a very successful year. We accomplished many of the goals we set out to achieve in our first full year of operation as a trust and we are very well positioned to deliver sustainable performance for our unitholders going forward.

The process of building our foundation for the long-term continued in 2005. We have a stable production base that is well positioned to offset production declines and provide paced growth. Our low cost structure on all fronts, including finding and development, operating, and general and administrative costs, remains among the leaders in our industry. Our inventory of drilling locations is as strong as it was one year ago confirming the value of the undeveloped land and the strength of our technical professionals to continuously replenish our opportunity set. Financially, our balance sheet remains very strong with low debt-to-cash flow. In 2005, our unitholders enjoyed a 42 percent total return.

Disciplined Value Creation **In 2005, we invested $107.7 million in our assets which included drilling 48 net wells and achieving a 90 percent success rate. We replaced 171 percent of production at a finding and development cost of $9.78 per barrel of oil equivalent ("boe") on a proved plus probable basis. Our three year average finding and development cost is $8.87 per boe on a proved and probable basis. Our proved plus probable reserve life index increased to 8.8 years from 8.1 years. On the production side, we produced 17,901 boe per day on average and exited the year at 18,700 boe per day.**

We made substantial investments for the future as well by investing approximately $13 million in land and seismic expenditures that will serve to extend our drilling inventory beyond 2007. Our exploration land base totals approximately 570,000 undeveloped acres which includes 500,000 net undeveloped acres, 50,000 royalty acres and 20,000 option acres under our control. Our inventory of 3-dimensional ("3-D") seismic data now covers nearly 865 square kilometers, predominantly shot in the northeast British Columbia Foothills. Another $24 million was invested in facility infrastructure which ensures that the Trust has operatorship and ownership in major oil and gas treatment and compression facilities that our production flows through.

$2.45

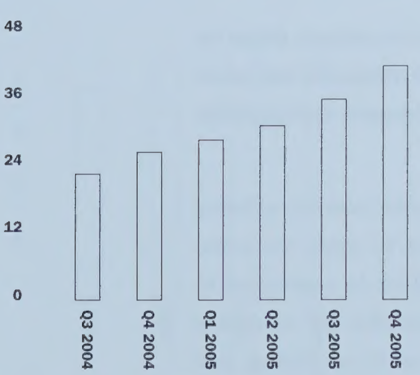
cash flow per unit, diluted, in 2005

57%

basic payout ratio in 2005

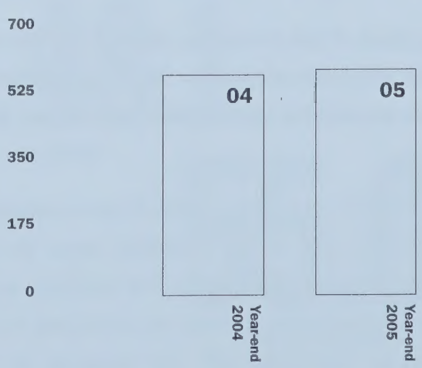
Strong Operating Netbacks

($ per boe)



Sustainable Reserves per Unit

(proved plus probable boe per 1,000 units)



Financial Results Cash flow was $206 million or $2.45 per unit, diluted in 2005. Our cash flow generating capability is enhanced by both the high heat content nature of our natural gas production, light sweet oil stream and the low operating cost profile of our operating regions.

We distributed $116.5 million or $1.68 per unit for an average payout ratio of 57 percent excluding exchangeable shares or 69 percent including exchangeable shares, well within our established target range of 60 to 70 percent.

Our balance sheet remains very strong with total debt-to-cash flow at year end of approximately 0.8 times our 2005 cash flow, positioning Progress to be both patient and opportunistic for the right opportunities.

High Quality Assets Our assets have the characteristics necessary for sustainability. We have a sufficiently large exploration land base in each region and we are actively adding to our undeveloped land position through crown land sales, farm-ins or when the opportunity presents itself, through asset acquisitions.

We have developed an inventory of drilling locations that provides approximately two years of drilling at our current pace and is continually reviewed and expanded based on the success of our exploration and development program.

We maintain high working interests and operatorship in the areas in which we work so that we can more effectively control the pace and the cost of development. Eighty-five percent of the Trust's production is from operated wells. In an environment of rising costs, it remains essential to be among the leaders in low cost production to withstand any potential down cycle in commodity prices. As well, our netbacks are enhanced by the high-heat content nature of our natural gas resulting in a premium price for our production as compared to the average market price at AECO, the main natural gas trading hub in western Canada.

Measuring Our Success Our success as a trust will be measured by our ability to sustain per unit reserves and production over the long-term while generating a stable stream of cash distributions to unitholders. On a per unit basis, we exited 2005 with the same amount of debt-adjusted production and grew the reserves underlying each unit of the Trust by over eight percent compared to one year earlier. In other words, after re-investing $107.7 million in our operations, paying out $116.5 million in cash to unitholders and strengthening our balance sheet, we still have the same amount of reserves and production underlying each unit as at the start of the year. That's sustainability!

With the depth of our inventory, the drill bit will continue to be our primary driver for production and reserves growth. We will continue to assess both corporate and asset acquisition candidates looking for those assets that meet our stringent sustainability criteria.

Our core strength lies in the ability of our employees to create value from the existing asset base. In each of our operating areas we have continued to apply the same disciplined, full-cycle approach to the business as Progress did prior to conversion to a trust. This has meant a focus on leveraging our technical strengths and remaining committed to controlling all cost aspects of the business such as finding and development costs and operating costs.

$10.37

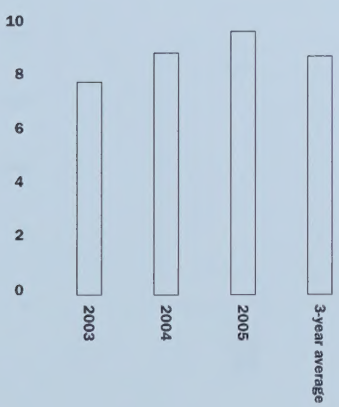
per boe, 2005 FD&A proved plus probable

171%

production replacement

Low Finding and Development Costs

($ per boe, proved plus probable)



Internally Generated Opportunities

(net wells drilled)

48.1
in 2005

55.0+
forecast in 2006

Outlook **At the time of writing this letter, natural gas prices have weakened through the winter resulting from a lack of weather related demand and unprecedented levels of gas in storage. Oil prices on the other hand have remained relatively strong in the US$60 per barrel range. Supply uncertainty resulting from the unrest in Iran and Nigeria and historically low spare OPEC capacity are the key themes.**

In 2006, we will continue to execute our business plan of sustainability through internally generated opportunities by investing approximately $100 million in our existing asset base and targeting average production of between 18,700 to 19,000 boe per day. Operating costs are expected to remain among the lowest in the industry at between $5.50 to $6.00 per boe. As part of our risk management program, we will continue to target up to 50 percent of before-royalty gas production for hedging. We have hedged approximately one-half of our natural gas production for the summer of 2006 at a net average floor price of $8.58 per gigajoule at AECO. This converts to a wellhead price of approximately $10.00 per thousand cubic feet.

Closing **Our Board is comprised of directors with strong industry knowledge, experience and integrity. They work closely with our Management team to realize Progress' potential. As well, the Board and Management remain firmly committed to maintaining a high level of corporate governance as is reflected in the Board's organization and responsibilities, and timeliness and thoroughness of the Trust's disclosure. A full discussion of the Board and committee responsibilities can be found in the Information Circular and on our website.**

I've mentioned our staff a number of times in this letter but I cannot emphasize enough the importance of having high quality employees and the contribution they make to Progress' success. All of our employees are owners in Progress Energy Trust either having participated in the original private placement or through the savings plan. In aggregate, employees, Management and Directors own 13 percent of the diluted units of the Trust providing a clear alignment with the interests of our unitholders.

On behalf of the Board of Directors and Management of Progress, we extend our appreciation to all our employees for the strong contribution they have made in creating value for our unitholders. To our unitholders, we thank you for your continued support and look forward to another strong year ahead.

Michael R. Culbert
President and CEO

February 23, 2006

$18,000

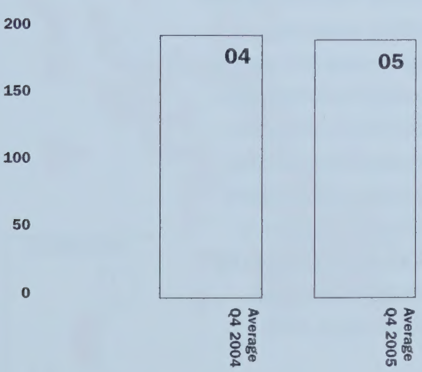
per boe per day, 2005 production on-stream cost

3.5x

2005 F&D proved plus probable recycle ratio

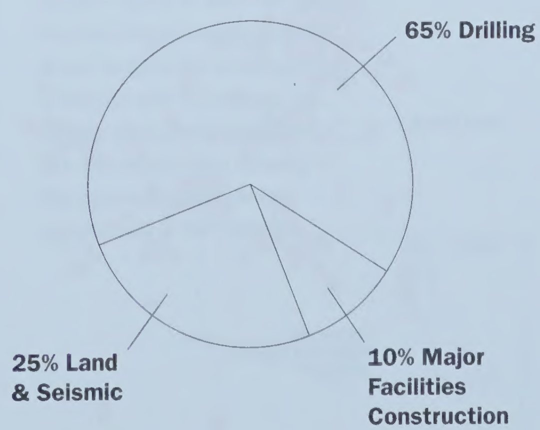
Sustainable Production per Unit

(boe per day per million units)



Investing for Sustainability

($100 million capital investment – 2006 forecast)



Alberta Deep Basin

Highly Desirable Region

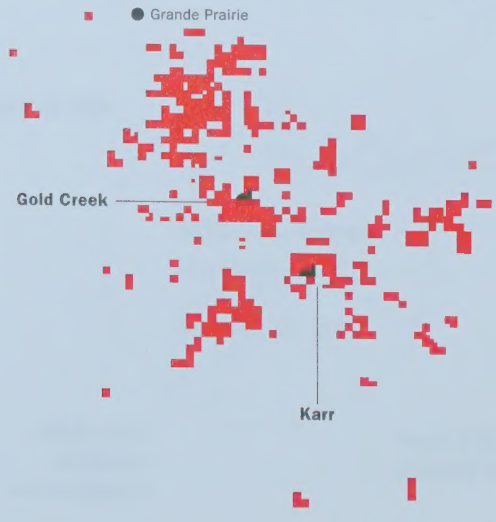
Progress holds over 150,000 net acres of undeveloped land in large contiguous blocks in the Deep Basin region of northwest Alberta. Its main producing areas at Gold Creek, Karr, Elmworth and Wapiti are located immediately south of Grande Prairie, a major petroleum industry service center in northwest Alberta. In 2005, the Trust added 22,900 net acres of undeveloped land through crown land sales and farm-ins.

Production of natural gas and natural gas liquids accounts for 90 percent of total production in the Deep Basin with the remaining 10 percent comprising light, high quality oil. The region is characterized as medium depth and multi-zone with up to 14 producing horizons in the Cretaceous and Triassic sections. A large number of reservoirs are found in the Cretaceous system with production from the Cadomin, Gething, Bluesky, Falher, Notikewan, Cadotte and Paddy. In the Triassic system, the main producing zones include the Halfway, Charlie Lake and Baldonnel.

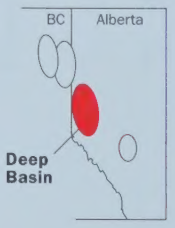
Strong operating netbacks in this region result from the high heat-content nature of the natural gas production and the lower operating cost structure. The region has a very well developed infrastructure and Progress' industry leading operating costs are supported by the Trust's ownership interest in two large gas plants at Gold Creek and Karr, each with capacity in excess of 100 million cubic feet per day.

In 2005, twenty-seven gross wells (17.8 net) were drilled in the Deep Basin with an 84 percent success rate. Production averaged 9,000 barrels of oil equivalent per day.

Alberta Deep Basin



Progress will invest approximately $40 million in the Deep Basin region in 2006. The Trust will keep one rig drilling constantly throughout the year with plans to drill between 20 to 25 net wells. Capital will also be invested in facilities construction, seismic data acquisition and additional land purchases. Production is expected to remain steady in the range of 9,000 barrels of oil equivalent per day in 2006.



British Columbia Foothills

Regional Tight Gas Play

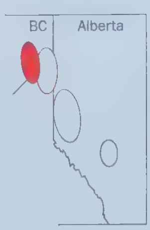
Approximately 100 kilometers northwest of Fort St. John, British Columbia, along the Alaska Highway, is the Trust's Foothills region. Major producing areas include a 100 percent working interest in the Town and Beg properties and generally, a 20 percent working interest in the West Beg, Gundy and Julienne properties. Progress currently holds approximately 75,000 net undeveloped acres. In 2005, the Trust added approximately 8,000 net acres of land in the region through a series of farm-ins and crown land sales and continues to actively pursue opportunities with its joint venture partner, ProEx Energy Ltd.

The primary producing focus of this region is the Halfway formation which is a thick, tight gas formation present at typical well depths of 1,800 meters. The regional analog is the Blueberry/Beg trend which is immediately east of the Trust's lands and has produced approximately 500 billion cubic feet of natural gas during the past 50 years and is expected to ultimately produce 1 trillion cubic feet of natural gas. The Halfway sandstone has a gross thickness of 100 to 150 feet and is gas-filled along the crest of the anticlinal folds that were created by westerly compression during Laramide mountain building time. The formation is tight with microdarcy permeability and porosity in the range of 5 to 12 percent. Advances in drilling and completions technology continue to open new opportunities in the region.

The Trust has used 3-D seismic imaging extensively in the Foothills to identify the crests and morphology of the anticlines. To date, Progress has shot or acquired 585 square kilometers of 3-D seismic data in the Foothills and will participate in a very large program in early 2006. Production in this region averaged 3,415 boe per day in 2005 and is expected to grow as the Trust and its joint venture partner actively drill in the region. The Trust drilled 23 gross wells (9.5 net) achieving a 100 percent success rate in 2005.

British Columbia Foothills Region

The Trust will invest approximately $20 million in the Foothills region in 2006 drilling 12 to 14 net wells. The Trust will participate in a deep Debolt target in the second quarter of the year with ProEx Energy Ltd. As well, the Trust will participate in a 3-D seismic shoot covering 280 square kilometers in the northern part of the Foothills.



Northeast British Columbia Foothills

Fort St. John Plains

Strong Cash-on-Cash Region

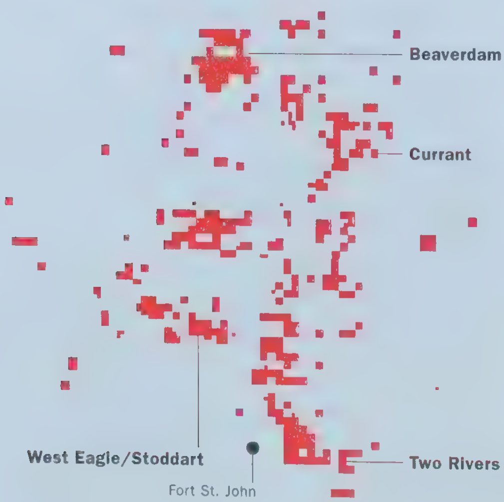
The Trust has a locally dominant position in the Fort St. John Plains region which is located on the northern flank of the Peace River Arch in northeast British Columbia. The Trust's main producing properties are at Two Rivers, Stoddart and West Eagle, all in close proximity to the city of Fort St. John, a major oil and gas hub in northeast British Columbia. The area is generally all-season accessible since the majority of the land is farming or ranching land.

The Fort St. John Plains region produces light oil and natural gas from a predictable sequence of porous Cretaceous fluvial derived sands and Triassic aged preserved sand dunes. Up to ten separate and distinct reservoirs can be encountered in a typical 1,200 meter well depth.

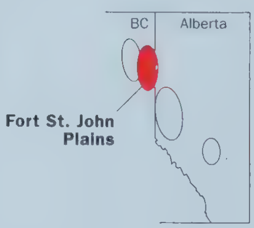
Progress maintains high working interests and operatorship in its main properties and will have one rig, on average, active in this region throughout 2006. The region has well developed infrastructure and raw gas is transported through the Duke Energy Gas Transmission system and processed at the McMahon gas processing facility near Fort St. John.

This region which represents approximately 10 percent of the Trust's production generates a steady stream of cash flow which can be deployed in the Trust's other growth regions. Production averaged 1,981 boe per day in 2005 and is expected to remain fairly constant as drilling plans are targeted to offset production declines. The Trust drilled 12 gross wells (7.0 net) achieving a 79 percent success rate in 2005.

Fort St. John Plains



The Trust will invest approximately $15 million in the Fort St. John Plains region in 2006 drilling 8 to 10 net wells. The primary focus will be the West Eagle, Stoddart and Currant properties. The Trust will also shoot a 2-dimensional seismic program in the West Eagle and Stoddart areas.



Central Alberta

Capturing Incremental Opportunities

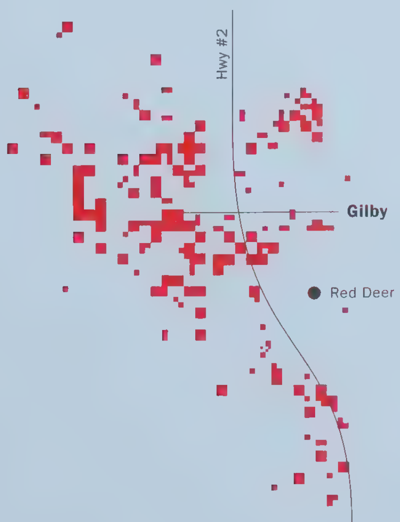
In the summer of 2005, the Trust identified a shallow gas play on its Gilby area lands in central Alberta and expanded its capital program in the fall to capture this opportunity. The Edmonton Sand is a pervasive shallow gas play located in close proximity to the city of Red Deer, mid-way in the Calgary-Edmonton corridor.

Progress had built a substantial undeveloped land base in the area previously exploring for deeper horizons. As other industry players proved up the play, Progress positioned itself to conduct an aggressive drilling program after the crops were removed from the farmers' fields in the fourth quarter of 2005.

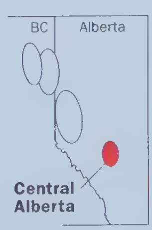
The Trust drilled 12 gross wells targeting the Edmonton Sand and achieved very strong results. Flow rates varied from 350 mcf to 1,000 mcf per day rendering the program very economic given the relatively inexpensive drilling costs. Further economies were achieved by conducting the program in a manufacturing style by sequentially drilling all of the wells, then completing the wells, and then tying-in the wells into the extensive area infrastructure.

Following the success of this program, Progress has identified another two years of drilling inventory on its lands, proving again the value of the undeveloped land and the ability of the Trust's technical professionals to create value.

Central Alberta



Approximately 12 wells will be drilled in the Gilby area in 2006 building upon the success of the 2005 drilling program. The Trust will also seek to strengthen its land base in the area as well as participate in the early phases of coalbed methane exploration in the area.



570,000+

hold over 500,000 net undeveloped acres, control another 70,000 royalty and option acres

200+

inventory of drilling locations

2006 Targets	Objectives
• Invest $100 million	• Stable stream of cash distributions
• Drill 55 to 65 net wells	• Sustain reserves and production per unit
• Production of between 18,700 and 19,000 boe per day	• Efficient reserve and production replacement
• Operating costs of $5.50 to $6.00 per boe	• Expand drilling inventory
• Capture land and shoot seismic	• Continuous focus on cost structures
	• Maintain strong balance sheet
	• Stay disciplined, we have investment choices

Reserve Information 2005

PROGRESS

Annual Report to Unitholders

PROGRESS ENERGY TRUST

R Reserve Information 2005

RESERVES – All future net revenues are stated prior to provision for interest, general and administrative expenses and after deduction of royalties and estimated future capital expenditures. Future net revenues have been presented on the basis that no income taxes will be paid by Progress in the future and therefore after-tax future net revenues from Progress' oil and gas reserves are equal to the before-tax future net revenues.

It should not be assumed that the present worth of estimated future cash flow presented in the tables represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Progress' crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

The Trust has adopted the standard of 6 mcf : 1 boe when converting natural gas to boe's. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf : 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserves

Progress' reserves were prepared by the independent engineering firm of GLJ Petroleum Consultants ("GLJ") in 2005 as well as prior years back to 2001. Reserves included herein are stated on a company interest basis (before royalty burdens and including royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument ("NI") 51-101. The Trust's actual natural gas and petroleum reserves and future production will be greater than or less than the estimates provided. The estimated future net revenue from the production of the Trust's natural gas and petroleum reserves does not represent the fair market value of the Trust's reserves. In addition to the information disclosed in this annual report, more detailed information on a net interest basis (after royalty burdens and including royalty interests) and on a gross interest basis (before royalty burdens and excluding royalty interests) is included in the Trust's Annual Information Form.

- Total proved reserves at December 31, 2005 increased eight percent to 46.0 million boe compared to 42.4 million boe in 2004.
- Total proved plus probable reserves at December 31, 2005 increased nine percent to 58.9 million boe compared to 54.3 million boe in 2004.
- Reserve growth in 2005 was achieved through the drill bit and replaced 171 percent of production on a proved plus probable basis and 154 percent on a proved basis.

2005 SUMMARY OF OIL AND GAS RESERVES

Forecast Prices and Costs

Company Interest

	Light and Medium Crude Oil	Natural Gas Liquids	Natural Gas	Total 2005	Total 2004
	(mbbls)	*(mbbls)*	*(bcf)*	*(mmboe)*	*(mmboe)*
Proved					
Developed producing	4,814	3,134	179.1	**37.79**	35.50
Developed non-producing	245	310	22.5	**4.31**	3.88
Undeveloped	780	295	16.7	**3.86**	3.06
Total proved	5,839	3,739	218.3	**45.96**	42.44
Probable	1,495	1,043	62.6	**12.96**	11.84
Total proved plus probable	7,334	4,781	280.8	**58.92**	54.28

Note: May not add due to rounding.

Forecast Prices and Costs

Net Present Value of Reserves

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 8%	Discounted at 10%
Proved				
Developed producing	1,135	854	757	708
Developed non-producing	118	90	80	74
Undeveloped	107	78	68	62
Total proved	1,359	1,023	905	844
Probable	406	215	166	144
Total proved plus probable	1,766	1,238	1,071	988

Note: May not add due to rounding.

Forecast Prices and Costs

Price Assumptions

The January 1, 2006 pricing forecasts presented below have been prepared by GLJ. These prices have been utilized in determining the reserves and cash flow forecasts.

Year	Crude Oil WTI	Crude Oil Edmonton Light	Natural Gas AECO	Natural Gas Sumas Spot	Inflation Rate
	($US/bbl)	*($Cdn/bbl)*	*($Cdn/MMBtu)*	*($US/MMBtu)*	*(%/Year)*
2006	57.00	66.25	10.60	9.40	2.0
2007	55.00	64.00	9.25	8.15	2.0
2008	51.00	59.25	8.00	7.00	2.0
2009	48.00	55.75	7.50	6.55	2.0
2010	46.50	54.00	7.20	6.30	2.0
2011	45.00	52.25	6.90	6.05	2.0
2012	45.00	52.25	6.90	6.05	2.0
2013	46.00	53.25	7.05	6.20	2.0
2014	46.75	54.25	7.20	6.30	2.0
2015	47.75	55.50	7.40	6.45	2.0
2016	48.75	56.50	7.55	6.60	2.0
Thereafter *(%/year)*	+2.0	+2.0	+2.0	+2.0	+2.0

Constant Prices and Costs

Net Present Value of Reserves

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 8%	Discounted at 10%
Proved				
Developed producing	1,350	1,001	876	812
Developed non-producing	149	112	97	89
Undeveloped	132	96	82	75
Total proved	1,631	1,208	1,055	976
Probable	476	264	205	178
Total proved plus probable	2,107	1,472	1,260	1,154

Note: May not add due to rounding.

Constant Prices and Costs

Price Assumptions

Year	Crude Oil WTI	Crude Oil Edmonton Light	Natural Gas AECO	Natural Gas Sumas Spot	Inflation Rate
	($US/bbl)	*($Cdn/bbl)*	*($Cdn/MMBtu)*	*($US/MMBtu)*	*(%/Year)*
2006	57.00	66.25	10.60	9.40	2.0

2005 RESERVE RECONCILIATION

Forecast Prices and Costs

Reconciliation of Company Interest Reserves by Principal Product Type

	Light and Medium Crude	Natural Gas	Natural Gas Liquids	Total
	(mbbl)	*(bcf)*	*(mbbl)*	*(mmboe)*
Proved Producing				
Opening balance	4,414	168.65	2,977	35.50
Exploration discoveries	–	5.66	32	0.98
Drilling extensions	160	15.82	239	3.04
Infill drilling	214	13.50	287	2.75
Improved recovery	368	2.85	87	0.93
Technical revisions	838	2.91	26	1.35
Acquisitions	–	–	–	–
Dispositions	(170)	(0.24)	(9)	(0.23)
Production	(1,011)	(30.09)	(506)	(6.53)
Closing Balance	4,814	179.07	3,134	37.79
Total Proved				
Opening balance	5,338	202.48	3,354	42.44
Exploration discoveries	–	0.72	7	0.13
Drilling extensions	160	24.60	422	4.68
Infill drilling	251	21.57	425	4.27
Improved recovery	439	1.84	57	0.80
Technical revisions	841	(2.62)	(11)	0.39
Acquisitions	–	–	–	–
Dispositions	(180)	(0.24)	(9)	(0.23)
Production	(1,011)	(30.09)	(506)	(6.53)
Closing Balance	5,839	218.28	3,739	45.96
Proved Plus Probable				
Opening balance	7,422	255.90	4,206	54.28
Exploration discoveries	–	0.94	9	0.16
Drilling extensions	199	35.45	592	6.70
Infill drilling	232	25.23	551	4.99
Improved recovery	441	2.07	61	0.85
Technical revisions	599	(7.84)	(106)	(0.81)
Acquisitions	–	–	–	–
Dispositions	(548)	(0.83)	(25)	(0.71)
Production	(1,011)	(30.09)	(506)	(6.53)
Closing Balance	7,334	280.84	4,781	58.92

Note: May not add due to rounding.

2005 FINDING AND DEVELOPMENT COSTS

Finding and development costs ("F&D") associated with the 2005 capital program, including revisions and the change in future development capital, were $11.36 per proved boe and $9.78 per proved plus probable boe. The three year average F&D costs, including revisions and the change in future capital, were $11.01 per proved boe and $8.87 per proved plus probable boe.

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	($ millions)	*(mmboe)*	*($/boe)*	*(mmboe)*	*($/boe)*
Total 2005 proved F&D costs including future development costs	116.8	10.28	11.36	n/a	n/a
Total 2005 proved plus probable F&D costs including future development costs	116.2	n/a	n/a	11.89	9.78
Three year average proved F&D costs including future development costs	320.9	29.14	11.01	n/a	n/a
Three year average proved plus probable F&D costs including future development costs	325.9	n/a	n/a	36.73	8.87

2005 FINDING, DEVELOPMENT AND NET ACQUISITION COSTS

Finding, development and acquisition costs ("FD&A") associated with the 2005 capital program, including revisions and the change in future capital, were $11.59 per proved boe and $10.37 per proved plus probable boe. Three year average FD&A costs, including revisions and the change in future development capital, were $16.18 per proved boe and $13.22 per proved plus probable boe. Three year average FD&A costs were negatively effected by the amalgamation with Cequel Energy Inc. and the inclusion of its assets at fair market value.

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	($ millions)	*(mmboe)*	*($/boe)*	*(mmboe)*	*($/boe)*
Total 2005 proved FD&A costs including future development costs	116.5	10.05	11.59	n/a	n/a
Total 2005 proved plus probable FD&A costs including future development costs	115.9	n/a	n/a	11.18	10.37
Three year average proved FD&A costs including future development costs	701.7	43.35	16.18	n/a	n/a
Three year average proved plus probable FD&A costs including future development costs	706.7	n/a	n/a	53.47	13.22

Reconciliation of Changes in Future Development Capital

In accordance with NI 51-101, the capital used to calculate F&D and FD&A costs has been adjusted to account for the change in future development capital. For that reason the capital may differ between the proved case and the proved plus probable case.

	Proved	Change	Proved Plus Probable	Change
2005	26.93	8.83	35.31	8.24
2004	18.10		27.07	

Reserve Life Index

The Trust's reserve life index ("RLI") using annualized fourth quarter production is 6.9 years proved (2004 – 6.3 years) and 8.8 years proved plus probable (2004 – 8.1 years).

	2005 Using Annualized Q4 Production	2005 Using 2006 GLJ Forecast Production	2004 Using Annualized Q4 Production	2004 Using 2005 GLJ Forecast Production
Production *(mmboe)*	6.683	6.808	6.704	6.821
Proved reserves *(mmboe)*	45.96	45.96	42.44	42.44
Proved RLI *(years)*	6.9	6.8	6.3	6.2
Production *(mmboe)*	6.683	7.204	6.704	7.221
Proved plus probable reserves *(mmboe)*	58.92	58.92	54.28	54.28
Proved plus probable RLI *(years)*	8.8	8.2	8.1	7.5

RESERVE REPLACEMENT

The Trust's 2005 capital program replaced production by a factor of 1.5 times on a proved basis and 1.7 times on a proved plus probable basis. Reserve growth in 2005 was achieved entirely through the drill bit.

	2005	2004 (1)
Production *(mmboe)*	**6.53**	4.95
Proved reserve additions *(mmboe)*	**10.05**	24.30
Proved placement ratio	**1.5**	4.9
Proved plus probable reserve additions *(mmboe)*	**11.18**	30.02
Proved plus probable replacement ratio	**1.7**	6.1

(1) The 2004 reserve additions include the acquisition of Cequel Energy Inc.

RECYCLE RATIO

The recycle ratio is a measure for evaluating the effectiveness of a company's reinvestment program. It accomplishes this by comparing the operating netback per boe to that year's reserve finding and development costs.

	2005	2004
Operating netback *($/boe)*	**34.51**	24.41
Proved F&D costs after revisions of prior periods and including the change in future development costs *($/boe)*	**11.36**	11.13
Proved recycle ratio	**3.0**	2.2
Proved plus probable F&D costs after revisions of prior periods and including the change in future development costs *($/boe)*	**9.78**	9.00
Proved plus probable recycle ratio	**3.5**	2.7

NET ASSET VALUE

The Trust's net asset value is measured with reference to the present value of future estimated cash flows from reserves estimates prepared by GLJ, the independent reserve engineers, and including undeveloped land, seismic data, adjustments for working capital deficiency, bank debt, convertible debenture and asset retirement obligations at year end. This calculation can vary significantly depending on the natural gas and oil price assumptions used by GLJ. This calculation does not represent a "going-concern" value since it only assumes the reserves contained in the GLJ report.

($ thousands, except per unit amounts)	2005 Constant Price	2005 Forecast Price	2004 Constant Price	2004 Forecast Price
Proved plus probable reserve value *(discounted at 10%)* (1)	1,154,100	988,243	744,477	679,160
Undeveloped acreage (2)	100,000	100,000	75,000	75,000
Seismic (3)	30,000	30,000	20,000	20,000
Working capital deficiency	(22,873)	(22,873)	(37,821)	(37,821)
Bank debt	(71,326)	(71,326)	(133,722)	(133,722)
Convertible debentures	(79,381)	(79,381)	–	–
Asset retirement obligations (4)	(12,706)	(12,706)	(7,465)	(7,465)
Net asset value	1,097,814	931,957	660,469	595,152
Total units outstanding and issuable for exchangeable shares *(thousands)*	84,784	84,784	82,189	82,189
Net asset value per unit	$12.95	$10.99	$8.04	$7.24

(1) Reserve values are based on after tax estimates of future cash flows as evaluated by our independent qualified reserve evaluators using their future commodity price forecasts as presented in the pricing assumptions on page R2.

(2) Based on internal estimate of market value considering recent sales of similar properties in the same general area.

(3) Seismic inventory values are an internal estimate of replacement value.

(4) Proved plus probable reserve value includes $8.2 million (2004 – $8.6 million) of asset retirement obligations on wells with assigned reserves.

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Management's Discussion and Analysis

MD&A

05

Annual Report to Unitholders

PROGRESS ENERGY TRUST

Management's Discussion and Analysis

The following discussion and analysis ("MD&A") of financial results, dated February 23, 2006, should be read in conjunction with Progress Energy Trust's ("Progress" or the "Trust") accompanying audited consolidated financial statements and related notes for the years ended December 31, 2005 and 2004. The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Non-GAAP Measurements Management uses cash flow from operations (before changes in non-cash working capital) ("cash flow") to analyze operating performance and leverage. The term distributable cash is also used to present the amount of cash that the Trust distributes to unitholders. Neither distributable cash nor cash flow presented have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Distributable cash and cash flow as presented are not intended to represent operating profit for the period nor should they be viewed as an alternative to operating profit, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The reconciliation between net earnings and cash flow can be found in the consolidated statements of cash flows in the audited year end financial statements. Distributable cash is calculated using cash flow less cash withheld for capital expenditures. The Trust considers cash flow to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investments. Both distributable cash and cash flow are used by research analysts to value and compare oil and gas trusts and are frequently included in published research when providing investment recommendations. Cash flow per unit is calculated using the diluted weighted average number of units for the period. All references to cash flow throughout the MD&A are based on cash flow before changes in non-cash working capital.

Management uses certain industry benchmarks such as operating netback and payout ratio to analyze financial and operating performance. These benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

Forward Looking Statements Certain information regarding Progress set forth in this document, including Management's assessment of Progress' future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Progress' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Progress' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Progress will derive therefrom.

Description of Business

Progress is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties. Progress Energy Ltd., a wholly owned subsidiary of Progress, carries on the business of the Trust and directly owns the petroleum and natural gas properties and assets related thereto. The Trust's unitholders and exchangeable shareholders are the sole beneficiaries of the Trust. Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust which is primarily comprised of interest earned on debt notes issued to Progress Energy Ltd., as well as,

amounts attributed to a net profits interest agreement entered into with Progress Energy Ltd. The aggregate amounts received by the Trust each period are based on the consolidated cash flow each period, as adjusted on a discretionary basis, for cash withheld to fund capital expenditures.

Progress is a Calgary based, natural gas focused, trust targeting sustainable production and reserves per trust unit through utilization of its technical capability and capital investment efficiencies. Primary operating areas include the Deep Basin of northwest Alberta and the northeast British Columbia Foothills and Fort St. John Plains regions. Trust units of Progress trade on the Toronto Stock Exchange ("TSX") under the symbol PGX.UN. Exchangeable shares and 6.75% convertible unsecured subordinated debentures (the "Debentures") of Progress trade on the TSX under the symbols PGE and PGX.DB respectively.

Transformation to a Trust

On July 2, 2004 Progress Energy Ltd. and Cequel Energy Inc. ("Cequel") amalgamated to create the Trust and two publicly listed, exploration-focused companies, ProEx Energy Ltd. ("ProEx") and Cyries Energy Inc. ("Cyries"), pursuant to a Plan of Arrangement ("Arrangement"). The Arrangement resulted in Progress Energy Ltd. shareholders receiving one trust unit or one exchangeable share of the Trust and 0.2 of a share in each of ProEx and Cyries for each common share held. Cequel shareholders received 0.695 trust units or exchangeable shares of the Trust and 0.139 of a share in each of ProEx and Cyries. Upon completion of the Arrangement, 65.4 million trust units and 16.0 million exchangeable shares were outstanding. Outstanding as at February 22, 2006 were 73.2 million trust units, 11.0 million exchangeable shares and $64.7 million convertible debentures convertible into 4.3 million trust units.

The Arrangement resulted in the Trust owning approximately 90 percent of the combined producing assets of Progress Energy Ltd. and Cequel. The remainder of the properties of Progress Energy Ltd. and Cequel were transferred to ProEx and Cyries, respectively, consisting of certain prospective natural gas weighted assets and undeveloped land.

The conversion of Progress Energy Ltd. to a Trust has been accounted for as a continuity of interest. Accordingly, the consolidated financial statements for 2005 and 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Progress Energy Ltd. The year ended December 31, 2004 reflects the results of operations and cash flows of Progress Energy Ltd. and its subsidiaries for the period January 1 to July 1, 2004 and the results of operations and cash flows of the Trust and its subsidiary for the period July 2 to December 31, 2004. Due to the conversion into an energy trust, certain information included in the MD&A for prior periods may not be directly comparable.

Relationship with ProEx

As a result of the Arrangement, the Trust and ProEx have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements and in addition the Trust has entered into a protocol arrangement ("Protocol Arrangement") and a technical services agreement ("Technical Services Agreement") with ProEx that specifies how each company will manage the joint lands in specifically identified areas of interest and allocate shared expenses. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

Protocol Arrangement In conjunction with the Arrangement, ProEx assumed the interest in certain of Progress' producing assets and undeveloped land. The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. The Protocol Arrangement also outlines the practices to be followed in the event either party enters into areas outside of identified areas of interest.

Technical Services Agreement In conjunction with the Arrangement, the Trust entered into a Technical Services Agreement with ProEx where the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and marketing of its production. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx.

OPERATING SUMMARY

In accordance with Canadian industry practice, production volumes, reserve volumes and revenues are reported on a Trust interest basis (working interest plus royalty interest), before deduction of crown and other royalties, unless otherwise indicated. The Trust's results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for this production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather and general economic conditions and changes in the Canadian/US currency exchange rate.

In this MD&A, production and reserves information may be presented on a "barrel of oil equivalent" or "boe" basis with six thousand cubic feet ("mcf") of natural gas being equivalent to one barrel of crude oil or natural gas liquids. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Production

	2005	2004	Change
Daily Production			
Natural gas *(mcf/d)*	**82,431**	62,221	32%
Crude oil *(bbls/d)*	**2,779**	2,335	19%
Natural gas liquids *(bbls/d)*	**1,384**	814	70%
Total daily production *(boe/d)*	**17,901**	13,519	32%
Natural gas as a % of total production	**77%**	77%	

Production in 2005 averaged 17,901 boe per day consisting of 82,431 mcf per day of natural gas, 2,779 bbls per day of crude oil and 1,384 bbls per day of natural gas liquids. This compares favorably to average production of 13,519 boe per day for the same period in 2004 mainly due to a full year of production from the Cequel acquisition and successful drilling in the northeast British Columbia Foothills and the Deep Basin of northwest Alberta regions. All production additions were through the drill bit during the year, confirming the Trust's commitment to sustainable production through drilling. Incremental production from the capital program served to offset the natural production declines on existing properties. The Trust replaced 171 percent of production on a proved plus probable basis and 154 percent on a proved basis. The Trust's production portfolio in 2005 was weighted 77 percent to natural gas, 15 percent to crude oil and eight percent to natural gas liquids.

The Trust's 2005 fourth quarter production averaged 18,312 boe per day, comprising of 85,173 mcf per day of natural gas, 2,762 bbls per day of crude oil and 1,355 bbls per day of natural gas liquids. This was consistent with the fourth quarter of 2004 with average production of 18,368, comprised of 86,998 mcf per day of natural gas, 2,475 bbls per day of crude oil and 1,394 bbls per day of natural gas liquids. For a full analysis of fourth quarter production refer to Fourth Quarter Analysis.

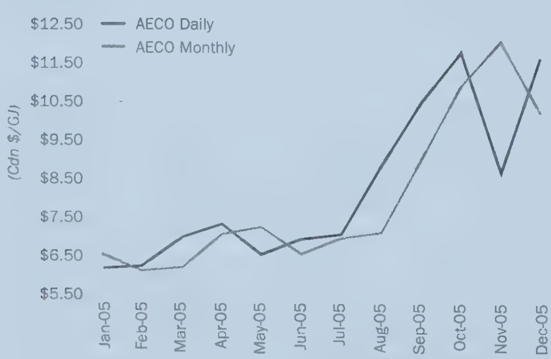
Progress' December 2005 production averaged approximately 18,700 boe per day and Management anticipates production to average between 18,700 and 19,000 boe per day in 2006. This estimate takes into account natural reservoir declines and forecasted capital expenditures of $100 million.

Production by Region

(boe/d)	**Fourth Quarter 2005**	Fourth Quarter 2004	Change	**2005**	2004	Change
Foothills	**3,690**	3,051	21 %	**3,415**	2,894	18 %
Fort St. John Plains	**2,117**	2,683	(21)%	**1,981**	2,968	(33)%
Other	**449**	574	(22)%	**501**	608	(18)%
Total British Columbia	**6,256**	6,308	(1)%	**5,897**	6,470	(9)%
Deep Basin	**8,957**	9,373	(4)%	**8,999**	4,174	116 %
Central Alberta	**1,440**	1,305	10 %	**1,461**	1,226	19 %
Other	**1,236**	1,036	19 %	**1,107**	1,151	(4)%
Total Alberta	**11,633**	11,714	(1)%	**11,567**	6,551	77 %
Saskatchewan	**423**	346	22 %	**437**	498	(12)%
Total daily production	**18,312**	18,368	–	**17,901**	13,519	32 %

Pricing and Risk Management

Monthly vs. Daily AECO Prices



WTI & Edmonton Mixed Sweet Oil Prices

Commodity pricing through 2005 continued upward from the record highs of 2004 as West Texas Intermediate ("WTI") crude oil established a new record in the third quarter as it averaged US$65.55 per barrel and both the New York Mercantile Exchange ("NYMEX") gas price and Canadian Alberta Energy Company interconnect with the TransCanada Alberta system ("AECO") gas price jumped to record averages of US$14.07 per MMbtu and Cdn$11.79 per gigajoule ("gj") respectively in the fourth quarter.

Rising oil prices helped support natural gas during the first quarter of 2005 as reduced demand for space heating resulted from warmer than normal weather throughout much of North America. As the market rolled through the second quarter, continued warmer than normal weather created high cooling demand and limited the markets ability to refill natural gas storage as gas was burned for incremental power generation. Crude

oil prices also continued upward during this time as inventories of crude oil and refined products remained low while the market expected inventories to increase prior to the high demand summer season. Hurricane damage to natural gas producing infrastructure in the southeastern United States ("US") impacted the third and fourth quarters creating concerns about the adequacy of supply in advance of the winter heating season. As a result of hurricane Katrina, the loss of Gulf of Mexico production and physical flooding of the "Henry Hub" market center in Louisiana, gas processing and oil refining facilities reduced supply to the point where significant price increases were the only way to reduce demand and balance the market. When the fourth quarter began, natural gas storage volumes were thought to be insufficient to meet winter demand which maintained upward pressure on natural gas prices until mid December when long range weather forecasts for predominantly warm weather and minimal storage withdrawals all but eliminated the supply risk for the balance of winter. WTI oil prices closed 2005 near an all time high as strong demand and relatively low inventories maintained upward pricing pressure.

As we look ahead to 2006, we expect to see WTI oil prices remain in the US$50.00 to US$60.00 per barrel range and natural gas at AECO to average between $6.00 and $8.00 per gj. Progress produces predominantly light oil and high heat content liquids rich natural gas that attract premium market prices.

Commodity Prices

	2005	2004	Change
Average Benchmark Prices			
Natural gas – AECO (daily) *($/gj)*	**8.26**	6.17	34 %
Natural gas – AECO (monthly) *($/gj)*	**8.04**	6.44	25 %
Crude oil – WTI *(US$/bbl)*	**56.56**	41.40	37 %
Crude oil – Edmonton par price *(Cdn$/bbl)*	**68.76**	52.54	31 %
Exchange rate – *(US$/Cdn$)*	**1.2114**	1.3012	(7)%
Average Realized Prices			
Natural gas – before hedging *($/mcf)*	**9.27**	7.08	31 %
Hedging settlements *($/mcf)*	**(0.17)**	0.13	(231)%
Amortization of hedge premiums *($/mcf)*	**(0.01)**	(0.03)	67 %
Amortization of commodity sales contract *($/mcf)* (1)	**0.02**	0.03	(33)%
Change in fair value of financial instruments *($/mcf)* (2)	**–**	(0.08)	100 %
Natural gas – after hedging *($/mcf)*	**9.11**	7.13	28 %
Crude oil – before hedging *($/bbl)*	**65.98**	50.72	30 %
Hedging *($/bbl)*	**–**	(5.05)	100 %
Amortization of hedge premiums *($/bbl)*	**–**	(0.23)	100 %
Crude oil – after hedging *($/bbl)*	**65.98**	45.44	45 %
Natural gas liquids *($/bbl)*	**57.20**	45.40	26 %

(1) Amortization of physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002. Contract expires in 2008.

(2) Change in fair value of financial instrument of ineffective hedges or contracts that did not qualify for hedge accounting.

Natural Gas Pricing

US natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta natural gas is referenced off the AECO Hub and British Columbia natural gas off of Sumas Washington or Station #2 market centers. Virtually all of Progress' natural gas is sold at market prices at one of the Alberta or British Columbia hubs. Progress typically sells 50 percent of its natural gas production on monthly indexes and 50 percent on daily indexes.

Natural Gas Production and Prices by Province

	2005		2004	
	(mcf/d)	*($/mcf)*	*(mcf/d)*	*($/mcf)*
Alberta	**52,059**	**9.39**	30,106	7.22
British Columbia	**29,198**	**9.12**	30,762	6.97
Saskatchewan	**1,174**	**7.83**	1,353	6.08
Total production and average sales price (1)	**82,431**	**9.27**	62,221	7.08

(1) Before the impact of hedging.

Alberta Natural Gas Prices

	2005	2004
NYMEX *(US$/mmbtu 12 month average – last 3 days)*	**8.55**	6.09
Less: AECO basis differential to Henry Hub *(US$/mmbtu)*	**(1.36)**	(1.09)
AECO *(US$/mmbtu)*	**7.19**	5.00
Average exchange rate	**1.2114**	1.3012
AECO price *(Cdn$/mmbtu daily average)*	**8.71**	6.51
Premium: Progress realized price vs spot (1)	**0.68**	0.71
Progress average realized Alberta price *(Cdn$/mcf)*	**9.39**	7.22

(1) Includes the conversion of mmbtu to mcf.

British Columbia Natural Gas Prices

	2005	2004
NYMEX *(US$/mmbtu 12 month average – last 3 days)*	**8.55**	6.09
Less: Station #2 basis differential to Henry Hub *(US$/mmbtu)*	**(1.50)**	(1.12)
Station #2 *(US$/mmbtu)*	**7.05**	4.97
Average exchange rate	**1.2114**	1.3012
Station #2 price *(Cdn$/mmbtu daily average)*	**8.54**	6.46
Premium: Progress realized price vs. spot (1)	**0.58**	0.51
Progress average realized British Columbia price *(Cdn$/mcf)*	**9.12**	6.97

(1) Includes the conversion of mmbtu to mcf.

Risk Management

The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. The Risk Management Policy has the following objectives:

- To reduce risk exposure to budgeted annual cash flow projections resulting from uncertainty or changes in commodity prices, interest rates or foreign exchange.
- To provide greater certainty and stability to monthly distributions.
- To limit the permissible structures to ensure hedging effectiveness.
- To limit hedging up to a maximum of 50 percent of budgeted production before royalties.
- To limit hedging activity to counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

In 2005, the Trust entered into a number of financial and physical transactions for natural gas, including monthly index swaps, put options, collars and call spread transactions. Progress' commodity risk management positions are described in note 12 in the consolidated financial statements attached. As at December 31, 2005 the Trust would have received $0.3 million on the termination of these contracts.

The Trust currently has natural gas financial and physical contracts in place for the following production volumes:

Financial Price Risk Management

	Contract Natural Gas Volumes *('000 gj/d)*	% of Estimated Natural Gas Production
First quarter of 2006	40.0	50
Second quarter of 2006	40.0	50
Third quarter 2006	40.0	50
Fourth quarter 2006	13.3	17

Sensitivities

Our risk management program will reduce, but not eliminate, the effects of changing commodity prices, exchange and interest rates and as a result cash flow remains sensitive to these changes as demonstrated by the following table:

	Estimated Effect on 2006 (1) Cash Flow per Trust Unit
Change of $0.25 per mcf in the price of natural gas	$0.07
Change of US$5.00 per barrel in the price of WTI	$0.06
Change of 5,000 mcf/d in natural gas production	$0.12
Change of 500 bbls/d in crude oil production	$0.09
Change of $0.01 in the US$/Cdn$ exchange rate	$0.03
Change of 1% in prime interest rates	$0.01

(1) These sensitivities reflect all commodity contracts as described in Note 12 of the consolidated financial statements. They apply to prices, production, interest and exchange rates within the context of current market rates. The sensitivities above will no longer apply above the ceiling or below the floor price limits set by existing commodity contracts.

Revenue

Petroleum and natural gas revenue increased 72 percent to $369.8 million in 2005 from $214.7 million in 2004 due to higher production volumes from a full year of production from the Cequel acquisition and successful drilling in the northeast British Columbia Foothills and Deep Basin, Alberta regions, as well as higher commodity prices. Production increased 32 percent from 13,519 boe per day in 2004 to 17,901 boe per day in 2005 while realized commodity prices increased 30 percent from $43.39 per boe in 2004 compared to $56.59 per boe in 2005. Petroleum and natural gas revenue in 2005 before hedging consisted of $279.0 million from natural gas sales, $66.9 million from crude oil sales and $28.9 million from the sale of natural gas liquids.

($ thousands)	**2005**	2004	Change
Natural gas sales	**278,978**	161,170	73 %
Crude oil sales	**66,914**	43,344	54 %
Natural gas liquids sales	**28,887**	13,526	114 %
Hedge settlements	**(5,217)**	(1,458)	(258)%
Amortization of hedge premiums	**(442)**	(909)	51 %
Amortization of a commodity sales contract (1)	**648**	762	(15)%
Change in the fair value of financial instruments (2)	**–**	(1,746)	–
Petroleum and natural gas revenue	**369,768**	214,689	72 %

(1) Amortization of physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002. Contract expires in 2008.

(2) Change in fair value of financial instrument of ineffective hedges or contracts that did not qualify for hedge accounting.

($ thousands)	Natural Gas	Crude Oil & NGLs	Total
2004 Petroleum and natural gas revenue	162,338	52,351	214,689
Price variance	59,488	26,789	86,277
Production variance	52,141	16,661	68,802
2005 Petroleum and natural gas revenue	**273,967**	**95,801**	**369,768**

Royalties

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners, net of credits received through the Alberta royalty tax credit program. Royalties increased 77 percent to $94.5 million in 2005 from $53.4 million in 2004 due to increased revenue primarily as a result of the Cequel acquisition, successful drilling and higher commodity prices. The Trust's average royalty rate in 2005 was 25.2 percent (before the impact of hedging charges) consistent with the average royalty rate in 2004 of 24.5 percent.

($ thousands)	**2005**	2004
Crown	**81,508**	44,482
Freehold and overriding	**12,984**	8,940
Total royalty expense	**94,492**	53,422
Royalties *($/boe)*	**14.46**	10.80
Average royalty rate *(after impact of hedging charges – %)*	**25.5**	24.9
Average royalty rate *(before impact of hedging charges – %)*	**25.2**	24.5

The following table provides a break down of royalties by product. Rates are calculated before the impact of hedging activities and Alberta royalty tax credit:

($ thousands)	**2005**	2004
Natural gas royalties	**71,530**	42,037
$/boe	**14.26**	11.08
Average natural gas royalty rate *(%)*	**25.6**	26.1
Crude oil royalties	**13,979**	7,773
$/boe	**13.78**	9.10
Average crude oil royalty rate *(%)*	**20.9**	17.9
Natural gas liquids royalties	**8,983**	3,612
$/boe	**17.78**	12.12
Average natural gas liquids royalty rate *(%)*	**31.1**	26.7

Management anticipates, based on current commodity prices that the average royalty rate for 2006, before the impact of hedging, will be approximately 26.0 percent of petroleum and natural gas revenue.

Operating Expenses

Operating expenses increased 28 percent to $37.2 million in 2005 compared to $29.1 million in 2004. The increase in operating expenses is mainly attributable to increased production. On a boe basis, operating expenses for 2005 decreased three percent to $5.69 from $5.87 in 2004. Progress has experienced increased costs for well servicing, insurance, workovers and well maintenance. Through increased operating efficiencies and the addition of low operating cost per boe production the Trust has been able to offset these increases and keep operating costs per boe flat year over year. Management anticipates continuing this trend and forecasts operating expenses for 2006 to be between $5.50 to $6.00 per boe.

($ thousands)	**2005**	2004	Change
Operating expenses – total	**37,170**	29,050	
$/boe	**5.69**	5.87	(3)%
Operating expenses – natural gas properties	**27,505**	19,203	
$/boe	**5.14**	4.82	7 %
Operating expenses – crude oil properties	**9,665**	9,847	
$/boe	**8.17**	10.20	(20)%

Transportation Expenses

Transportation expenses increased 10 percent to $12.6 million in 2005 compared to $11.4 million in 2004. On a boe basis, transportation expenses in 2005 decreased 16 percent to $1.93 compared to $2.31 in 2004. The decrease on a boe basis is mainly attributable to a decrease in the proportion of production from British Columbia. As a result of the Cequel acquisition the Trust's production in British Columbia went from representing 48 percent of total production in 2004 to 33 percent in 2005. In British Columbia, there is an infrastructure owned by Duke Energy that enables gas producers to avoid facility construction in exchange for gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Operating Netbacks

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the higher proportion of natural gas or crude oil production. The following table summarizes the operating netbacks for natural gas, oil properties and all properties combined:

	2005	2004
Natural Gas Properties ($/mcf)		
Sales price – before hedging	**9.33**	7.10
Hedging settlements	**(0.16)**	0.10
Amortization of hedge premiums	**(0.01)**	(0.02)
Amortization of commodity sales contract	**0.02**	0.03
Change in fair value of financial instruments	–	(0.06)
Royalties	**(2.40)**	(1.81)
Operating expenses	**(0.86)**	(0.80)
Transportation expenses	**(0.32)**	(0.32)
Operating netback – natural gas properties	**5.60**	4.22
Oil Properties ($/bbl)		
Sales Price – before hedging	**63.52**	48.10
Hedging settlements	–	(4.47)
Amortization of hedge premiums	–	(0.21)
Royalties	**(14.65)**	(10.61)
Operating expenses	**(8.17)**	(10.21)
Transportation expenses	**(1.88)**	(1.88)
Operating netback – oil properties	**38.82**	20.72
All Properties ($/boe)		
Sales Price – before hedging	**57.36**	44.07
Hedging settlements	**(0.80)**	(0.34)
Amortization of hedge premiums	**(0.07)**	(0.14)
Amortization of commodity sales contract	**0.10**	0.15
Change in fair value of financial instrument	–	(0.35)
Royalties	**(14.46)**	(10.80)
Operating expenses	**(5.69)**	(5.87)
Transportation expenses	**(1.93)**	(2.31)
Operating netback – all properties	**34.51**	24.41

General and Administrative Expenses

General and administrative expenses net of overhead recoveries on operated properties, ("G&A") increased 31 percent to $6.7 million ($1.03 per boe) in 2005 compared to $5.1 million ($1.04 per boe) in 2004. The increase in G&A expense is due to additional full-time and contract staff added as a result of the Cequel acquisition.

($ thousands)	2005	2004
Gross G&A	**14,962**	10,019
Technical Services Fees from ProEx	**(2,759)**	(556)
Operator recoveries	**(4,112)**	(2,833)
Capitalized expenses	**(1,345)**	(1,492)
G&A expense	**6,746**	5,138
G&A ($/boe)	**1.03**	1.04

In conjunction with the Arrangement, the Trust entered into a Technical Services Agreement with ProEx where the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expenses reimbursed by ProEx in 2005 were $2.8 million ($0.6 million in 2004).

The magnitude of operator recoveries is a function of activity levels and the degree to which operations are operated by the Trust. Progress operates 85 percent of its production and operates the majority of the drilling and construction activity. Operator recoveries for 2005 were $4.1 million compared to $2.8 million in 2004. This increase is primarily a result of increased operator recoveries associated with well operations. The number of operated wells increased as a result of the Cequel acquisition.

The Trust capitalized approximately $1.4 million of G&A in 2005 and $1.5 million in 2004. The majority of these costs represent geological and geophysical employee compensation.

Management anticipates G&A expense to remain consistent with 2005 and average in the range of $1.00 to $1.20 per boe in 2006.

Unit Based Compensation Expenses

($ thousands)	**2005**	2004
Unit based compensation expenses	**3,029**	502
Unit based compensation expenses *($/boe)*	**0.46**	0.10

The Trust's Performance Unit Incentive Plan (the "Plan") provides for employees and directors to be granted performance units by the Board of Directors of Progress Energy Ltd. from time to time at its sole discretion. The performance units vest on the third anniversary of the date of grant and actual payment will be based on a performance factor ranging from 0.5 to 1.5 times the initial performance units granted which will be determined based on the performance of the Trust relative to its peers. The performance units entitle the employee or director to a specific number of trust units and the accumulated distributions those trust units earned over the three year vesting period. Payment may be in the form of cash or trust units, at the Trust's option. Management anticipates, at the end of the performance period, accumulated distributions will be paid in cash and trust units will be paid from treasury.

The Board of Directors of Progress Energy Ltd. granted 395,267 performance units effective July 2, 2004. As a result, the fair value of the performance units granted, calculated using a performance factor of 1.0, was approximately $5.3 million of which $4.7 million will be amortized through unit based compensation expense and $0.6 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

The Board of Directors of Progress Energy Ltd. granted 512,500 performance units effective July 2, 2005. The fair value of the performance units using a performance factor of 1.0 was approximately $8.0 million of which $6.9 million will be amortized through unit based compensation expense and $1.1 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

Management anticipates unit based compensation expenses will increase to approximately $0.75 per boe in 2006 as an additional layer of performance units are granted.

Interest and Financing Expenses

Interest and financing expenses in 2005 increased 209 percent to $10.6 million compared to $3.4 million in 2004. The increase is primarily due to higher average debt levels due to the Arrangement, as well as interest, accretion and amortization of issue costs on the $100 million principal amount of Debentures issued on February 2, 2005. The Debentures pay interest semi-annually, have a maturity date of June 30, 2010 and are convertible, at the option of the holder, at any time into fully paid trust units of Progress at a conversion price of $15.00 per trust unit. The net proceeds of the financing were used to reduce outstanding bank indebtedness.

($ thousands)	**2005**	2004
Interest on bank debt	**3,030**	3,431
Interest on Debentures	**6,012**	–
Amortization of Debenture issue costs	**754**	–
Accretion on debt portion of Debentures (1)	**793**	–
Total interest and financing expense	**10,589**	3,431
Interest and financing expense *($/boe)*	**1.62**	0.69
Average bank debt outstanding	**73,581**	99,179
Average bank debt interest rate *(%)*	**4.2**	3.5

(1) Under Canadian GAAP, the fair value of the conversion feature of the Debentures is classified as equity and the remainder is classified as debt. Over the term of the Debentures, the debt portion will accrete up to the principal balance at maturity with the charge going to interest and financing expenses.

Depletion, Depreciation and Accretion

Depletion and depreciation of property, plant and equipment and the accretion of the asset retirement obligations ("DD&A") increased 56 percent to $92.0 million in 2005 from $59.2 million in 2004. The increase is due to both higher production and a higher depletable base as a result of the Cequel acquisition, as well as, new accounting for exchangeable shares whereby the conversion of exchangeable shares results in a charge to property, plant and equipment and is depleted over time. On a boe basis DD&A year over year has increased due to the acquisition of Cequel and the inclusion of these assets at their fair market value, as well as the accounting for exchangeable shares. DD&A per boe in 2005 was $14.09 compared to $11.96 in 2004.

($ thousands)	**2005**	2004
Depletion	**89,956**	57,714
Depreciation	**637**	376
Accretion of asset retirement obligations	**1,447**	1,083
Total DD&A expense	**92,040**	59,173
DD&A *($/boe)*	**14.09**	11.96
DD&A rate *(%)*	**3.6**	3.5

Income and Capital Taxes

Capital taxes were $2.2 million in 2005 and $1.5 million in 2004. This increase is primarily attributable to an increase in total debt and equity levels as a result of the Cequel acquisition.

The provision for future income taxes in 2005 increased to an expense of $4.1 million from a recovery of $4.4 million in 2004 due primarily to higher earnings in 2005 from both higher production and commodity prices. For the year ended December 31, 2005 the provision for future income taxes includes a charge of $3.5 million due to adjustments relating to tax audits performed on the 2002 and 2003 tax returns for both Cequel and Progress Energy Ltd. and a recovery of approximately $2.0 million due to a reduction in the British Columbia provincial income tax rate. The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. It is expected the Trust will not incur any cash income taxes in the future and as such the future tax liability recorded on the balance sheet will recover through future net earnings.

Non-Controlling Interest – Exchangeable Shares

On March 8, 2005 the accounting abstract "Exchangeable Securities Issued by Subsidiaries of Income Trusts" was amended effective for financial statements issued on or after June 30, 2005. Under the amended abstract, exchangeable shares are presented as equity of the Trust only if the exchangeable shares are entitled to receive distributions of earnings economically equivalent to distributions received by units of the trust and the holders of exchangeable shares can only dispose of them by exchanging them for trust units. The exchangeable shares of the Trust's subsidiary trade on the TSX, thereby allowing holders of the exchangeable shares to dispose of them without having to exchange them for trust units and consequently, they must be classified as non-controlling interest outside of unitholders' equity. The net earnings attributable to the exchangeable shares is charged to earnings as non-controlling interest with a corresponding increase to non-controlling interest on the consolidated balance sheet.

The following details the non-controlling interest activity for the years ended December 31, 2005 and 2004:

	2005		2004	
($ thousands, except unit amounts)	**Number**	**Amount**	Number	Amount
Balance, beginning of year	**14,533,506**	**141,060**	–	–
Issued for common shares	–	–	6,999,994	20,300
Issued on Cequel acquisition	–	–	9,000,000	126,369
Exchanged for trust units	**(3,144,755)**	**(31,816)**	(1,466,488)	(13,571)
Non-controlling interest expense		**17,961**		7,962
Balance, end of year	**11,388,751**	**127,205**	14,533,506	141,060

The charge to net earnings of $18.0 million for 2005 and $8.0 million for 2004 represents the net earnings attributable to the exchangeable shares over the year.

Net Earnings and Cash Flow

Net earnings increased 101 percent to $88.9 million in 2005 compared to $44.2 million in 2004. The increase was primarily due to increased production and increased commodity prices. Basic net earnings in 2005 were $1.29 per trust unit compared to $0.89 per trust unit in 2004. Similarly, diluted net earnings in 2005 were $1.27 per trust unit compared to $0.88 per trust unit in 2004.

Cash flow increased 86 percent to $206.0 million in 2005 compared to $110.5 million in 2004 mainly due to higher commodity prices and increased production. Diluted cash flow in 2005 was $2.45 per trust unit compared to $1.87 per trust unit in 2004.

QUARTERLY FINANCIAL SUMMARY (1) (2)

	Three Months Ended							
($ thousands, except per unit amounts)	**Dec. 31 2005**	**Sept. 30 2005**	**Jun. 30 2005**	**Mar. 31 2005**	Dec. 31 2004	Sept. 30 2004	Jun. 30 2004	Mar. 31 2004
Petroleum and natural gas revenue	**114,167**	**93,372**	**83,222**	**79,007**	76,767	68,299	38,811	30,812
Cash flow	**65,785**	**53,215**	**44,466**	**42,511**	41,344	36,355	17,833	14,928
Per unit diluted	**0.77**	**0.63**	**0.53**	**0.52**	0.50	0.45	0.49	0.41
Net earnings	**29,398**	**25,159**	**16,840**	**17,527**	18,196	15,324	4,464	6,247
Per unit basic	**0.41**	**0.36**	**0.25**	**0.27**	0.28	0.24	0.13	0.19
Per unit diluted	**0.40**	**0.36**	**0.24**	**0.27**	0.28	0.24	0.12	0.17

(1) The above amounts have been restated for changes in accounting policies related to asset retirement obligations, transportation expense and non-controlling interest. Refer to Note 1 in the consolidated financial statements attached.

(2) Quarterly petroleum and natural gas revenue and cash flow increased in the third and fourth quarter of 2004 primarily as a result of increasing production from the Cequel acquisition and successful drilling in the northeast British Columbia Foothills region, partially offset by the transfer of assets to ProEx as part of the Arrangement. Quarterly petroleum and natural gas revenue and cash flow increased in 2005 mainly as a result of increased commodity prices.

SELECTED ANNUAL INFORMATION

($ thousands, except per unit amounts)	**2005**	2004	2003
Petroleum and natural gas revenue	**369,768**	214,689	107,539
Net earnings	**88,924**	44,231	21,245
Per unit basic	**1.29**	0.89	0.68
Per unit diluted	**1.27**	0.88	0.63
Cash flow	**205,977**	110,460	54,255
Per unit diluted	**2.45**	1.87	1.61
Total assets	**1,152,985**	1,093,268	252,112
Distributions declared	**116,460**	55,705	–
Working capital deficiency	**22,873**	37,820	10,360
Bank debt	**71,326**	133,722	45,073
Convertible debentures	**79,381**	–	–
Total debt	**173,580**	171,542	55,433

Distributable Cash and Distributions

Management monitors the Trust's distribution payout policy with respect to forecasted cash flow, debt levels and capital expenditures. Progress expects to distribute approximately 60 to 70 percent of its annual cash flow to unitholders and retain the remaining cash flow for capital expenditures and debt repayment. The Trust distributed 57 percent of cash flow to unitholders in 2005 (69 percent including exchangeable shares). Exchangeable shares are convertible into trust units of the Trust based on the exchange ratio, which is adjusted monthly to reflect that distributions are not paid on the exchangeable shares and cash flow related to the exchangeable shares is retained by the Trust for additional capital expenditures or debt repayment. The key drivers of Progress' cash flow, as is generally the case with other energy trusts, are commodity prices and production. Since the Trust's production is heavily weighted to natural gas (77 percent in 2005), natural gas prices have a significant effect on its cash flow.

Distributable cash is not a measure under Canadian GAAP and there is no standard measure of distributable cash. Distributable cash, as presented, may not be comparable to similar measures presented by other trusts. Progress' initial cash distribution declared was $0.14 per trust unit for the month of July 2004. The Trust has maintained this cash distribution to date.

($ thousands, except per unit amounts)	**2005**	Six Months Ended December 31, 2004
Cash flow	**205,978**	77,699
Cash withheld to fund capital expenditures	**89,518**	21,994
Cash distributions declared	**116,460**	55,705
Accumulated cash distributions, beginning of period	**55,705**	–
Accumulated cash distributions, end of period	**172,165**	55,705
Cash distributions per unit (1)	**1.68**	0.84
Accumulated cash distributions per unit, beginning of period	**0.84**	–
Accumulated cash distributions per unit, end of period	**2.52**	0.84

(1) Cash distributions per trust unit reflect the sum of the per trust unit amounts paid and declared to unitholders.

Capital Expenditures

The Trust invested approximately $107.7 million in capital expenditures in 2005 compared to $106.4 million in 2004.

($ thousands)	**2005**	2004
Land acquisitions and retention	**8,340**	9,883
Geological and geophysical	**4,442**	7,225
Drilling and completions	**70,230**	57,177
Equipping and facilities	**23,932**	32,679
Net property acquisitions (dispositions)	**(334)**	(1,986)
Corporate assets	**1,048**	1,444
Total capital expenditures	**107,658**	106,422

Progress drilled 88 gross wells (48.1 net) with a 90 percent success rate in 2005. Included in this drilling activity was 27 gross wells (17.8 net) drilled in the Deep Basin region of northwest Alberta, 23 gross wells (9.5 net) in the Foothills region of northeast British Columbia, 12 gross wells (7.0 net) in the Fort St. John Plains region of northeast British Columbia and 20 gross wells (11.1 net) in central Alberta.

The 2006 capital investment program will be directed to the Trust's three focus regions; the Deep Basin in northwest Alberta and the Fort St. John Plains and Foothills regions of northeast British Columbia. Progress expects to drill 55 to 65 net wells on a capital program totaling $100.0 million. The Trust's capital investment program is expected to be split approximately 65 percent to drilling and completions, 10 percent to major facilities and 25 percent to land and seismic expenditures. The Trust does not set a budget for property acquisitions.

Undeveloped Land

Undeveloped land at year end decreased 12 percent compared to 2004 due to conversions to developed land, expiries and a conversion of working interest land to royalty acreage of approximately 25,000 acres. The Trust purchased approximately 25,000 net acres at Crown land sales during 2005 and acquired 7,600 net freehold acres in Progress' core regions. Progress continues to maintain a high working interest in its undeveloped land. Progress' average working interest in its undeveloped land at year end was 68 percent. At year end the Trust had an option to earn an interest in 22,500 gross acres of undeveloped land in British Columbia. The Trust, at its option, can earn an interest in part or all of these lands by drilling up to four wells.

(acres)	**2005 Gross**	**2005 Net**	2004 Gross	2004 Net
Alberta	**345,660**	**288,019**	412,238	333,245
British Columbia	**336,868**	**158,498**	322,316	164,276
Saskatchewan	**56,783**	**55,684**	77,141	71,958
Total undeveloped land	**739,311**	**502,201**	811,695	569,479

Over the next 12 months 110,600 net acres or 22 percent of Progress' undeveloped land will be subject to expiry. The Trust has an active capital program and farmout strategy in place with 94,600 net acres of undeveloped land committed under farmout agreements at normal industry terms.

Goodwill

The goodwill balance of $414.7 million is primarily the result of the acquisition of Cequel in 2004. In accordance with Canadian GAAP goodwill is not amortized but is subject to an impairment test. Progress conducts a goodwill impairment test on an annual basis at its fiscal year end. Goodwill may be tested for impairment between annual tests in certain situations. There was no impairment of goodwill as a result of the tests conducted at December 31, 2005 and 2004.

Liquidity and Capital Resources

($ thousands, except per unit amounts)	**2005**	2004
Working capital deficiency	**22,873**	37,821
Bank debt	**71,326**	133,722
Convertible debentures	**79,381**	–
Total debt	**173,580**	171,543
Units outstanding and issuable for exchangeable shares *(thousands)*	**84,784**	82,189
Market price per unit at end of year	**17.17**	13.52
Market value of trust units and exchangeable shares	**1,455,741**	1,111,208
Cash flow	**205,977**	110,460
Total debt to cash flow ratio	**0.84**	1.55

At December 31, 2005 the Trust had $71.3 million outstanding on its credit facility of $215.0 million, as well as $79.4 million for the debt portion of the Debentures and a working capital deficiency of $22.9 million, totaling $173.6 million of total debt. The Trust currently has a $200 million extendible revolving term credit facility and a $15 million working capital credit facility with a syndicate of banks. The facilities are available on a revolving basis for a period of at least 364 days until May 30, 2006, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. The credit facilities are secured by a $500 million fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress Energy Ltd. in respect of the Trust's obligations. The $215 million borrowing base is subject to semi-annual review by the banks.

Bank debt decreased from $133.7 million as at December 31, 2004 to $71.3 million as at December 31, 2005. This decrease is primarily the result of the issuance of Debentures during the first quarter of 2005. Working capital deficiency decreased from $37.8 million as at December 31, 2004 to $22.9 million as at December 31, 2005 due to increased accrued accounts receivable as a result of increased commodity prices in December 2005 compared to December 2004.

On February 2, 2005 the Trust issued $100 million principal amount of 6.75 percent convertible unsecured subordinated debentures for net proceeds of $95.5 million. The Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $15.00 per trust unit. The Debentures mature on June 30, 2010 at which time they are due and payable. The net proceeds were used to reduce outstanding bank indebtedness.

The Debentures have been classified as debt net of the fair value of the conversion feature which has been classified as part of unitholders' equity and net of issue costs. This resulted in $90.5 million being classified as debt and $4.9 million being classified as equity. Issue costs are amortized over the term of the Debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed within interest and financing expense on the consolidated statements of earnings.

During the year ended December 31, 2005, $13.8 million principal of convertible debentures were converted to trust units. This resulted in a reduction to the debt portion of the convertible debentures on the consolidated balance sheet of $12.7 million, a reduction to the equity portion of the convertible debentures of $0.7 million and an increase to Unitholders' capital of $13.4 million.

The Trust's investing activities for 2005 primarily consists of expenditures on the capital program. Management anticipates that the Trust will continue to have adequate liquidity to fund future working capital and forecasted capital expenditures during 2006 through a combination of cash flow and debt. Cash flow used to finance these commitments may reduce the amount of cash distributions paid to unitholders.

Off Balance Sheet Arrangements

The Trust has no guarantees or off-balance sheet arrangements, except for letters of credit which have been issued in the normal course of business of approximately $0.9 million as at December 31, 2005 for transportation and derivative financial instruments as described in the "Risk Management" section of the MD&A.

Unitholders' Equity

At December 31, 2005, there were 84.8 million trust units issued and issuable for exchangeable shares, a three percent increase from the 82.2 million trust units issued and issuable for exchangeable shares at December 31, 2004. The increase in the number of trust units and issuable exchangeable shares is attributed to 0.9 million units issued on the conversion of debentures and the increase in the conversion ratio of exchangeable shares.

Contractual Obligations and Commitments

The Trust contracts for firm transportation on the TransCanada and Atco systems in Alberta and the Duke Energy system in British Columbia. Currently, the Trust is in the process of negotiating a multi-year tolling agreement with Duke Energy for raw gas transmission and treatment services in northeast British Columbia. The table below includes the terms of this pending contract.

The Trust has an office lease commitment that extends to 2009. Annual costs of this lease commitment, which include rent and operating expenses, amount to $1.5 million.

The Trust must pay crown royalty, surface rentals, mineral taxes and abandonment and reclamation costs with respect to its ongoing ownership of hydrocarbon production rights. The amounts paid with respect to these burdens will depend on the future ownership, production, prices and legislative environment at the time.

Production of 6,300 mcf per day is dedicated to certain aggregator sales arrangements. Under these arrangements, Progress receives a price based on the average netback price of the pool, net of transportation expenses incurred by the aggregator.

		Minimum Annual Commitment			
($ thousands)	Total	2006	2007	2008 - 2009	2010 - 2011
Bank debt (1)	71,326	–	71,326	–	–
Pipeline commitments	34,521	6,990	7,015	12,490	8,026
Drilling rig commitments	7,748	3,613	3,105	1,030	–
Office lease	4,684	493	1,479	2,712	–
Total	118,279	11,096	82,925	16,232	8,026

(1) Based on the existing terms of the revolving credit facilities which are subject to renewal on or before May 30, 2006. If not extended, the facilities would be available on a non-revolving basis for a one-year term at which time the facilities would be due and payable.

In addition, the Trust has entered into certain derivative financial instruments under its commodity risk management program, the terms and commitments of which are disclosed in note 12 of the consolidated financial statement.

FOURTH QUARTER ANALYSIS

	Q4 2005	Q3 2005	Q4 2004
Operational Highlights			
Daily Production			
Natural gas *(mcf/d)*	85,173	80,804	86,998
Crude oil *(bbls/d)*	2,762	2,734	2,475
Natural gas liquids *(bbls/d)*	1,355	1,280	1,394
Total daily production *(boe/d)*	18,312	17,481	18,368
Average Benchmark Prices			
Natural gas – AECO (daily) *($/gj)*	10.72	8.81	6.10
Natural gas – AECO (monthly) *($/gj)*	11.08	7.75	6.72
Crude oil – WTI *(US$/bbl)*	60.02	63.19	48.28
Crude oil – Edmonton par price *(Cdn$/bbl)*	71.21	76.54	57.74
Exchange rate *(US$/Cdn$)*	1.1732	1.2015	1.2210
Average Realized Prices			
Natural gas – before hedging *($/mcf)*	12.18	9.33	7.32
Natural gas – after hedging *($/mcf)*	11.38	9.11	7.45
Crude oil – before hedging *($/bbl)*	67.22	72.66	55.69
Crude oil – after hedging *($/bbl)*	67.22	72.66	48.21
Natural gas liquids *($/bbl)*	63.63	62.68	48.24
Financial Highlights *($ thousands, except per unit amounts)*			
Petroleum and natural gas revenue	114,167	93,372	76,767
Royalties	(30,964)	(23,136)	(19,572)
Operating expenses	(9,534)	(9,160)	(9,383)
Transportation expenses	(3,185)	(3,135)	(3,309)
General and administrative expenses	(1,258)	(1,342)	(1,924)
Unit based compensation expense	(1,002)	(1,004)	(171)
Cash flow	65,785	53,215	41,344
Depletion, depreciation and accretion	23,342	22,934	22,936
Net earnings	29,398	25,159	18,196
Per unit basic	0.41	0.36	0.28
Per unit diluted	0.40	0.36	0.28
Capital Expenditures	35,227	24,492	33,994

Production

Production during the fourth quarter of 2005 increased by five percent to 18,312 boe per day compared to 17,481 boe per day in the third quarter of 2005, and was consistent with the fourth quarter of 2004 at 18,368 boe per day. The production increase from the third quarter to the fourth quarter in 2005 was primarily the result of wells returning to production after scheduled plant maintenance at the Duke Energy owned McMahon gas processing facility in northeast British Columbia during the third quarter.

Revenue

Petroleum and natural gas revenue for the fourth quarter of 2005 increased 22 percent to $114.2 million compared to the third quarter of 2005 of $93.4 million and increased 49 percent over the $76.8 million recognized for the fourth quarter of 2004. The increase in revenue in the fourth quarter of 2005 compared to the third quarter of 2005 and the fourth quarter of 2004 is primarily the result of increased natural gas prices.

Royalties

Royalties for the fourth quarter of 2005 increased 34 percent to $31.0 million compared to the third quarter of 2005 of $23.1 million and increased 58 percent over the $19.6 million recognized for the fourth quarter of 2004. The average royalty rate (before the impact of hedging charges) for the fourth quarter of 2005 was approximately 25.7 percent compared to 24.3 percent in the third quarter of 2005 and 25.3 percent in the fourth quarter of 2004. The higher royalty rate in the fourth quarter of 2005 compared to the third quarter of 2005 is due to higher production and natural gas prices.

Operating Expenses

Operating expenses for the fourth quarter of 2005 of $9.5 million were consistent with both the third quarter of 2005 of $9.2 million and the fourth quarter of 2004 of $9.4 million. Operating expenses during the fourth quarter of 2005 averaged $5.66 per boe compared to $5.70 per boe during the third quarter of 2005 and $5.55 per boe during the fourth quarter of 2004.

Transportation Expenses

Transportation expenses for the fourth quarter of 2005 of $3.2 million were consistent with both the third quarter of 2005 of $3.1 million and the fourth quarter of 2004 of $3.3 million. Transportation expenses during the fourth quarter of 2005 averaged $1.89 per boe compared to $1.95 per boe during the third quarter of 2005 and $1.96 per boe during the fourth quarter of 2004. Approximately 34 percent of the Trust's production is in British Columbia where there is an infrastructure owned by Duke Energy that enables gas producers to avoid facility construction in exchange for gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

General and Administrative Expenses

G&A expenses for the fourth quarter of 2005 of $1.3 million were consistent with the third quarter of 2005 of $1.3 million and decreased 35 percent over the fourth quarter of 2004 of $1.9 million. The decrease from the fourth quarter of 2004 is the result of a higher allocation of costs to ProEx due to its increased production levels. G&A expenses averaged $0.75 per boe during the fourth quarter of 2005 compared to $0.83 in the third quarter of 2005 and $1.14 during the fourth quarter of 2004.

Depletion, Depreciation and Accretion

DD&A expense for the fourth quarter of 2005 was $23.3 million compared to $22.9 million for the third quarter of 2005 and the fourth quarter of 2004. The increase in the fourth quarter is due to both higher production and a higher depletable base in 2005 due to the Cequel acquisition as well as, new accounting for exchangeable shares whereby the conversion of exchangeable shares result in a charge to property, plant and equipment and is depleted over time. This resulted in DD&A of $13.86 per boe for the fourth quarter of 2005 compared to $14.26 per boe for the third quarter of 2005 and $13.57 for the fourth quarter of 2004. On a boe basis, DD&A in 2005 increased due to the acquisition of Cequel and the inclusion of these assets at their fair market value, as well as the accounting for exchangeable shares.

Income and Capital Taxes

Capital taxes for the fourth quarter of 2005 remained consistent to the third quarter of 2005 and the fourth quarter of 2004 of $0.5 million.

The provision for future income taxes in the fourth quarter of 2005 increased to an expense of $6.6 million from a recovery of $1.0 million in the third quarter of 2005 and a recovery of $4.5 million in the fourth quarter of 2004. The increase is primarily due to higher earnings in the fourth quarter of 2005 due to both higher production and commodity prices. The provision for the third quarter of 2005 also includes a recovery of approximately $2.0 million due to a reduction in the British Columbia provincial income tax rate. The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. It is expected the Trust will not incur any cash income taxes in the future and as such the future tax liability recorded on the balance sheet will recover through future net earnings.

Net Earnings and Cash flow

Net earnings for the fourth quarter of 2005 were $29.4 million compared to $25.2 million for the third quarter of 2005 and $18.2 million for the fourth quarter of 2004. The increase in net earnings over both the third quarter of 2005 and fourth quarter of 2004 is mainly due to higher revenues from increased commodity prices and production.

Cash flow for the fourth quarter of 2005 increased 24 percent to $65.8 million compared to the third quarter of 2005 of $53.2 million and increased 59 percent compared to the fourth quarter of 2004 of $41.3 million. The increase was primarily due to higher commodity prices.

Capital Expenditures

During the fourth quarter of 2005 the Trust incurred $35.5 million on exploration and development capital including $4.3 million in land acquisition and retention, $2.1 million in geological and geophysical, $23.2 million in drilling and completions and $5.9 million in facility construction. During the fourth quarter the Trust drilled 31 gross wells (17.7 net) with 8 gross wells (3.3 net) drilled in the northeast British Columbia Foothills, 2 gross wells (1.1 net) drilled in the Fort St John Plains, 5 gross wells (2.5 net) drilled in the Deep Basin of northwest Alberta, 15 gross wells (9.8 net) drilled in central Alberta and one gross well (one net) drilled in northern Alberta.

Net capital investment during the fourth quarter was $35.2 million compared to $24.5 million in the third quarter of 2005 and $34.0 million in the fourth quarter of 2004.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with Canadian GAAP requires Management to make judgments and estimates that affect the financial results of the Trust. Progress' Management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. A summary of significant accounting policies are presented in Note 1 to the consolidated financial statements. The critical estimates are discussed below:

Petroleum and Natural Gas Reserves

All of Progress' petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The evaluation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

Depletion Expense

The Trust uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation expense.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion expense.

Asset Retirement Obligations

The asset retirement obligations is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

CHANGE IN ACCOUNTING POLICIES

During 2005, the following new or amended standards and guidelines were issued:

Exchangeable Securities Issued by Subsidiaries of Income Trusts

On March 8, 2005 the accounting abstract "Exchangeable Securities Issued by Subsidiaries of Income Trusts" was amended effective for financial statements issued on or after June 30, 2005. Under the amended abstract, exchangeable shares are presented as equity of the Trust only if the exchangeable shares are entitled to receive distributions of earnings economically equivalent to distributions received by units of the trust and the holders of exchangeable shares can only dispose of them by exchanging them for trust units. The exchangeable shares of the Trust's subsidiary trade on the Toronto Stock Exchange, thereby allowing holders of the exchangeable shares to dispose of them without having to exchange them for trust units and consequently, they must be classified as non-controlling interest outside of unitholders' equity.

In accordance with the transitional provisions of the abstract, the Trust has retroactively restated prior periods dating back to the Arrangement dated July 2, 2004. As a result of this change in accounting policy, the Trust has reflected a non-controlling interest on the consolidated balance sheet of $127.2 million as at December 31, 2005 and $141.1 million as at December 31, 2004. For the year ended December 31, 2005, non-controlling interest decreased and unitholders' capital increased by $31.8 million for exchangeable shares redeemed for trust units (2004 – $13.6 million). Each redemption of exchangeable shares held by previous Progress Energy Ltd. shareholders are accounted for as a step-purchase resulting in an increase to property, plant and equipment of $22.2 million (2004 – $10.4 million), an increase to unitholders' capital of $14.6 million (2004 – $6.8 million) and an increase in the Trust's future income tax liability of $7.6 million (2004 – $3.6 million). Non-controlling interest expense, representing the amount of net earnings attributable to the exchangeable shares, for the year ended December 31, 2005 was $18.0 million (2004 – $8.0 million). Cash flow was not impacted by this change in accounting policy. The effect of the adoption on previously reported amounts is presented in the notes to the consolidated financial statements.

Internal Control Reporting

Proposed multilateral Instrument 52-111 Reporting on Internal Control over Financial Reporting and 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings set out the key provisions relating to the evaluation, assessment and certification of the internal controls over financial reporting ("ICOFR") by Management of the Trust, and the audit by Progress' external auditors of Managements' assessment of ICOFR. The objective of the new rules is to improve the quality and reliability of financial reporting by requiring issuers to evaluate the controls over the preparation of financial statements. The proposed new rules are expected to be phased in with final implementation of the evaluation of the effectiveness by Management and attestation by the external auditors of ICOFR for financial years ended after June 29, 2006. Progress has developed a plan and will be in full compliance by the final phase in date.

RECENT ACCOUNTING PRONOUNCEMENTS

In 2005, the Canadian Institute of Chartered Accountants issued several standards relating to the accounting and disclosure of financial instruments. The standards, 3855 – "Financial Instruments – Recognition and Measurement", 3861 Financial Instruments – Disclosure and Presentation, 1530 – "Comprehensive Income" and 3865 – "Hedges", are effective for fiscal years beginning on or after October 1, 2006. The standards require all financial instruments other than held-to-maturity investments, loans and receivables, to be included on a company's balance sheet at their fair value. Held-to-maturity investments, loans and receivables would be measured at their amortized cost. The standards create a new statement for comprehensive income that will include changes in the fair value of certain derivative financial instruments. The Trust has not yet determined the impact these standards will have on its financial statements.

RISK FACTORS AND RISK MANAGEMENT

Investors that purchase trust units are participating in the net cash flow from a portfolio of natural gas and crude oil producing properties. As such, the cash flow paid to investors and the value of Progress' units is subject to numerous risk factors. Some of the risks are common to all businesses while many are associated with the oil and gas industry. The following information is only a summary of certain risk factors which could affect the Trust's future results:

Volatility of Commodity Prices

The Trust's results of operations and financial condition are dependent on prices received for the production of natural gas and crude oil. With the Trust's production heavily weighted to natural gas, changes to natural gas prices have the most material effect on its cash flow. Prices for natural gas and crude oil have fluctuated significantly during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of the Trust. Prices received from production in Canada also reflect changes in the Canadian/US currency exchange rate. Any decline in the prices for natural gas and crude oil could have a material adverse effect on the Trust's operations, financial condition and the level of capital expenditures provided for the development of its natural gas and crude oil reserves.

Progress uses financial derivative instruments in an effort to limit a portion of the potential adverse effects resulting from volatility in natural gas and crude oil commodity prices, while retaining exposure to upside price movements. The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. To the extent commodity price exposure is hedged, the benefits that would otherwise be experienced if commodity prices were to increase would be foregone.

Operational Matters

The ownership and operation of oil and natural gas wells, pipelines and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to the Trust's natural gas and oil properties and assets as well as possible liability to third parties. The Trust may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the cash flow of Progress.

Progress employs prudent risk management practices and maintains suitable liability insurance, where available. Business interruption insurance is also purchased for selected facilities, to the extent that such insurance is reasonably available.

Reserve Estimates

Estimates of economically recoverable natural gas and crude oil reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating expenses. All of these estimates may vary from actual results. Estimates of the recoverable natural gas and crude oil reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Trust's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Each year, a firm of independent engineers evaluates a significant portion of proved and probable reserves. At December 31, 2005 100 percent of the reserves were evaluated by GLJ.

Exploration and Development Risks

Oil and gas exploration and development requires manpower and capital to generate, develop and test exploration concepts. The eventual testing of a concept will not necessarily result in the discovery of economical reserves.

Progress attempts to minimize the risk of developing existing and new reserves by ensuring that: (a) the majority of prospects have multi-zone potential (b) activity is focused in core areas were expertise and experience is greatest (c) the number of wells drilled is large enough to increase the probability of statistical success rates (d) geophysical techniques are utilized where appropriate (e) by focusing its activities in core areas and major play types, allows it to leverage off its experience and knowledge in these areas further aiding efficiencies and (f) farm-outs are entered into to minimize risk on plays it considers higher risk.

Access to Capital Markets

The Trust distributes the majority of its cash flow to unitholders. Access to equity and debt markets may be required for the Trust to finance acquisition and development activity to maintain and grow value to unitholders.

Progress' trust units are listed on the TSX and the Trust maintains an active investor relations program designed to facilitate access to the equity capital markets. Progress also maintains a prudent capital structure by retaining a portion of its net cash flow for debt repayment when appropriate, managing capital expenditures within rate of return risk parameters and by utilizing equity markets.

Regulatory Risk

There can be no assurance that government royalties, income tax laws, environmental laws and regulatory requirements relating to the oil and gas industry, such as the status of mutual fund trusts, will not be changed in a manner which adversely affects the Trust or its unitholders. For example, the tax efficiency of Progress is contingent upon its status as a mutual fund trust under Canadian tax law and therefore may be subject to unanticipated legislative and/or regulator modification.

Although the Trust has no control over these regulatory risks, Progress continuously monitors changes in these areas by participating in industry organizations and conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on the Trust's financial and operating results.

Environment and Safety Risks

The Canadian oil and natural gas industry is subject to environmental and safety regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Trust or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Trust.

The Board of Directors has reviewed and approved policies and procedures covering environmental risks, emergency response and employee safety. These policies and procedures are designed to protect and maintain the environment with respect to all corporate operations on behalf of unitholders, employees and the public at large. The Trust mitigates environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations and maintaining adequate insurance.

Credit Risks

The Trust assumes customer credit risk associated with natural gas and crude oil sales, financial hedging transactions and joint venture participants.

Management has established controls designed to mitigate the risk of default or non-payment with respect to natural gas and crude oil sales, financial hedging transactions and joint venture participants.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's Management, as appropriate, to allow timely decisions regarding required disclosures. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings that the Trust's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Trust. It should be noted that while the Trust's Chief Executive Officer and Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

OUTLOOK AND 2006 FORECAST

Progress will continue to pursue a disciplined approach to long term sustainability on a per unit basis. Our technical approach and cost control will be primary contributors to sustained value creation for unitholders. Internally generated opportunities will be drilled at a more modest pace than when we were an aggressive growth company. Our inventory of drilling locations currently supports approximately two years of activity for Progress while our over 500,000 net acres of undeveloped land provides the opportunity for our technical team to create incremental value.

In creating our Trust, we ensured that we would have access to strong technical and financial staff by having all employees invest in Progress. This creates strong alignment with our unitholders and ensures that we have the professionals to execute our business plan. Employees, Management and Directors hold a 13 percent direct ownership interest in our Trust.

The following table summarizes the Trust's 2006 forecast provided throughout the MD&A. Progress does not forecast commodity prices and, as a result, the Trust does not provide a forecast of future cash distributions to unitholders.

2006 Forecast

	Target
Average annual Production	18,700 to 19,000 boe/d
Royalty rate before hedging charges	26 percent
Operating expenses	$5.50 to $6.00 per boe
G&A expenses	$1.00 to $1.20 per boe
Unit based compensation expenses	$0.75 per boe
Capital expenditures	$100 million
Drilling activity	75 to 85 gross or 55 to 65 net wells
Pay-out ratio target	60 to 70 percent

Additional Information

Additional information regarding the Trust and its business and operations, including the annual information form ("AIF") is available on the Trust's company profiles at www.sedar.com. Copies of the AIF can also be obtained by contacting the Trust at Progress Energy Trust 1400, 440 – 2nd Avenue S.W., Calgary, Alberta, Canada T2P 5E9 or by e-mail at ir@progressenergy.com. This information is also accessible on the Trust's web site at www.progressenergy.com.

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Consolidated Financial Statements and Notes

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Consolidated Financial Statements and Notes

REPORT OF MANAGEMENT

The accompanying consolidated financial statements of Progress Energy Trust and all the information in this annual report are the responsibility of management and have been approved by the Trust's Board of Directors.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Progress Energy Trust maintains appropriate systems of internal accounting and administrative controls of high quality. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Trust's assets are properly accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee of the Board of Directors, composed entirely of independent directors, meets regularly with Management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy and financial reporting matters. The committee reviews the financial statements and Management's Discussion and Analysis and recommends their approval to the Board of Directors. The Committee also considers, for review by the board and approval by the unitholders, the engagement or re-appointment of the external auditors.

The financial statements have been audited by KPMG LLP, the external auditors, in accordance with generally accepted auditing standards on behalf of the unitholders. KPMG LLP has full and free access to the Audit Committee.

Art MacNichol

Michael R. Culbert
President and CEO
Progress Energy Ltd.

Art A. MacNichol
Vice President, Finance and CFO
Progress Energy Ltd.

February 23 , 2006

AUDITORS' REPORT

To the Unitholders of Progress Energy Trust

We have audited the consolidated balance sheets of Progress Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of earnings and deficit and cash flows for the years ended December 31, 2005 and 2004. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatements. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years ended December 31, 2005 and 2004 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Calgary, Canada
February 23, 2006

KPMG LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ thousands)	**2005**	2004
		(Restated – Notes 1 and 8)
ASSETS		
Current		
Cash and short-term investments	**–**	–
Accounts receivable	**45,870**	30,863
Prepaid expenses and deposits	**5,144**	4,370
	51,014	35,233
Property, plant and equipment *(Note 4)*	**687,316**	643,380
Goodwill *(Note 2)*	**414,655**	414,655
	1,152,985	1,093,268
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**58,904**	56,978
Cash distributions payable	**9,982**	9,366
Current income taxes payable	**5,001**	6,709
	73,887	73,053
Bank debt *(Note 5)*	**71,326**	133,722
Convertible debentures *(Note 6)*	**79,381**	–
Commodity sales contract *(Note 12)*	**1,446**	2,094
Asset retirement obligations *(Note 7)*	**20,906**	16,065
Future income taxes *(Note 10)*	**124,186**	112,483
	371,132	337,417
NON-CONTROLLING INTEREST		
Exchangeable shares *(Notes 1 and 8)*	**127,205**	141,060
UNITHOLDERS' EQUITY		
Unitholders' capital *(Note 9)*	**681,263**	621,490
Convertible debentures *(Note 6)*	**4,261**	–
Contributed surplus *(Note 9)*	**3,530**	171
Deficit	**(34,406)**	(6,870)
	654,648	614,791
Commitments *(Note 13)*		
	1,152,985	1,093,268

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board

David D. Johnson
Director

Donald F. Archibald
Director

CONSOLIDATED STATEMENTS OF EARNINGS AND DEFICIT

Year ended December 31 ($ thousands, except per unit amounts)	**2005**	2004
		(Restated – Notes 1 and 8)
REVENUE		
Petroleum and natural gas	**369,768**	214,689
Royalties	**(94,492)**	(53,422)
	275,276	161,267
EXPENSES		
Operating	**37,170**	29,050
Transportation	**12,578**	11,433
General and administrative	**6,746**	5,138
Unit based compensation *(Note 9)*	**3,029**	502
Interest and financing	**10,589**	3,431
Depletion, depreciation and accretion	**92,040**	59,173
Plan of arrangement *(Note 3)*	–	3,314
	162,152	112,041
Earnings before taxes and non-controlling interest	**113,124**	49,226
TAXES		
Capital taxes	**2,172**	1,454
Future income taxes *(Note 10)*	**4,067**	(4,421)
	6,239	(2,967)
Net earnings before non-controlling interest	**106,885**	52,193
Non-controlling interest – exchangeable shares *(Notes 1 and 8)*	**17,961**	7,962
NET EARNINGS	**88,924**	44,231
Retained earnings, beginning of year	**1,476**	36,290
Retroactive application of change in accounting policy *(Notes 1 and 8)*	**(8,346)**	(1,510)
Deficit, beginning of year, as restated	**(6,870)**	34,780
Plan of arrangement *(Note 3)*	–	(30,176)
Distributions	**(116,460)**	(55,705)
Deficit, end of year	**(34,406)**	(6,870)
NET EARNINGS PER UNIT *(Note 9)*		
Basic	**$1.29**	$0.89
Diluted	**$1.27**	$0.88

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 ($ thousands)	**2005**	2004
		(Restated – Notes 1 and 8)
OPERATING ACTIVITIES		
Net earnings	**88,924**	44,231
Depletion, depreciation and accretion	**92,040**	59,173
Non-controlling interest – exchangeable shares *(Note 8)*	**17,961**	7,962
Convertible debentures accretion *(Note 6)*	**793**	–
Amortization of convertible debenture issue costs *(Note 6)*	**755**	–
Amortization of commodity sales contract *(Note 12)*	**(648)**	(762)
Unit based compensation expense *(Note 9)*	**3,029**	2,889
Asset retirement expenditures	**(944)**	(358)
Change in fair value of financial instruments *(Note 12)*	–	1,746
Future income taxes	**4,067**	(4,421)
	205,977	110,460
Changes in non-cash working capital *(Note 11)*	**(14,886)**	21,971
	191,091	132,431
FINANCING ACTIVITIES		
Increase (decrease) in bank debt	**(62,396)**	44,176
Issue of 6.75% convertible debentures *(Note 6)*	**100,000**	–
Convertible debenture issue costs *(Note 6)*	**(4,515)**	–
Cash distributions	**(115,843)**	(46,339)
Issue of units	–	8,403
Unit issue costs	–	(2,001)
Plan of arrangement *(Note 3)*	–	(21,943)
Changes in non-cash working capital *(Note 11)*	–	(268)
	(82,754)	(17,972)
INVESTING ACTIVITIES		
Corporate acquisition *(Note 2)*	–	(1,597)
Capital expenditures	**(107,658)**	(106,422)
Change in non-cash working capital *(Note 11)*	**(679)**	(6,440)
	(108,337)	(114,459)
CHANGE IN CASH AND SHORT-TERM INVESTMENTS	–	–
Cash and short-term investments, beginning of year	–	–
CASH AND SHORT-TERM INVESTMENTS, END OF YEAR	–	–

See accompanying notes to the consolidated financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts are in $ thousands except for trust units and per trust unit amounts)

Progress Energy Trust ("Progress" or the "Trust") is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties through investments in securities of subsidiaries and royalty interests in petroleum and natural gas properties. Progress Energy Ltd. carries on the business of the Trust and directly owns the petroleum and natural gas properties and assets related thereto. The Trust owns, directly and indirectly, 100 percent of the common shares (excluding the exchangeable shares – see notes 1 and 8) of Progress Energy Ltd. The activities of Progress Energy Ltd. are financed through interest bearing notes from the Trust and third party debt. The convertible debentures are direct obligations of the Trust. Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust, which is primarily comprised of interest earned on debt notes issued to Progress Energy Ltd., as well as, amounts attributed to a net profits interest ("NPI") agreement entered into with Progress Energy Ltd. The aggregate amounts received by the Trust each period are based on the consolidated cash flow from operations before changes in non-cash working capital each period, as adjusted on a discretionary basis, for cash withheld to fund capital expenditures.

Pursuant to the terms of the NPI agreement, the Trust is entitled to a payment from Progress Energy Ltd. each month equal to the amount by which 99% of the gross proceeds from the sale of production exceed 99% of certain deductible expenditures (as defined). Under the terms of the NPI agreement, deductible expenditures may include amounts, determined on a discretionary basis, to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of Progress Energy Ltd.

The Trust was established as part of a Plan of Arrangement (the "Arrangement") that became effective on July 2, 2004. The Arrangement gave effect to the transaction contemplated by the agreement entered into on May 28, 2004 by Progress Energy Ltd. and Cequel Energy Inc. ("Cequel"). The reorganization resulted in the shareholders of Progress Energy Ltd. and Cequel receiving trust units or exchangeable shares in the Trust, a new energy trust that owns approximately 90 percent of the combined assets of Progress Energy Ltd. and Cequel. In addition, the shareholders of Progress Energy Ltd. and Cequel received shares in two separate, publicly-listed, exploration-focused companies, ProEx Energy Ltd. ("ProEx") and Cyries Energy Inc. ("Cyries"). The remaining properties were transferred to ProEx and Cyries, respectively, consisting of certain prospective natural gas weighted assets and undeveloped land.

Pursuant to the Arrangement, shareholders of both Progress Energy Ltd. and Cequel received shares of both ProEx and Cyries and at their election, either units of the Trust or exchangeable shares which may be exchanged into units of the Trust. The Arrangement resulted in Progress Energy Ltd. shareholders receiving one trust unit or one exchangeable share of the Trust and 0.2 of a share in each of ProEx and Cyries. Cequel shareholders received 0.695 trust units or exchangeable shares of the Trust and 0.139 of a share in each of ProEx and Cyries.

Upon completion of the Arrangement, 65.4 million trust units and 16.0 million exchangeable shares were outstanding.

The conversion of Progress Energy Ltd. to a Trust has been accounted for as a continuity of interest. Accordingly, the consolidated financial statements reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Progress Energy Ltd. The year ended December 31, 2004 reflect the results of operations and cash flows of Progress Energy Ltd. and its subsidiaries for the period January 1 to July 1, 2004 and the results of operations and cash flows of the Trust and its subsidiary for the period July 2 to December 31, 2004. Due to the conversion into an energy trust, certain information included in the financial statements for prior periods may not be directly comparable.

Relationship with ProEx

In conjunction with the Arrangement, the Trust entered into a Technical Services Agreement with ProEx where the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx and the marketing of its production. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. As contemplated in the Arrangement, ProEx has granted performance shares to the employees of Progress as service providers. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expense reimbursed by ProEx for the year ended December 31, 2005 was $2.8 million (2004 – $0.6 million).

As a result of the Arrangement the Trust and ProEx have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements and in addition the Trust has entered into a Protocol Arrangement with ProEx that specifies how each company will manage the joint lands in specifically identified areas of interest. The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

As at December 31, 2005, accounts payable included $1.8 million (2004 – $4.1 million) payable to ProEx which includes standard joint venture amounts including revenue. These amounts were paid subsequent to year end. In July 2004, the Trust sold ProEx $3.1 million of assets it purchased earlier in 2004, in contemplation of the formation of ProEx. The assets primarily consisted of undeveloped land.

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

The Trust is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta and Saskatchewan. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiary.

Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Trust only reflects its proportionate interest in such activities.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the asset retirement obligations and related accretion are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Cash and Short-Term Investments

Cash and short-term investments consist of cash in the bank, less outstanding cheques and short-term deposits with a maturity of less than three months.

Petroleum and Natural Gas Properties

The Trust uses the full cost method of accounting for petroleum and natural gas properties under which all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

In accordance with the full cost accounting guideline, the Trust evaluates its oil and gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the oil and gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

Depletion and Depreciation

Capitalized costs, together with estimated future capital costs associated with proven reserves, are depleted and depreciated using the unit-of-production method based on estimated proved reserves of petroleum and natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

Other assets, which is comprised of office equipment and furniture and fixtures, are recorded at cost and are depreciated over their useful life on a declining balance basis at 20%.

Asset Retirement Obligations

The Trust records a liability for the fair value of future asset retirement obligations in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset within property, plant and equipment, which is depleted on a unit-of-production basis over the life of the reserves. Estimates used are evaluated on a periodic basis and any adjustments are applied prospectively. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability. No gains or losses on retirement activities were realized due to settlements approximating the estimates.

Goodwill

Goodwill is recognized on corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets of the acquired company. Goodwill is tested for impairment on an annual basis in the fourth quarter. If indications of impairment are present, a loss would be charged to earnings for the amount that the carrying value of goodwill exceeds its fair value.

Financial Instruments

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Trust may enter into crude oil and natural gas swap contracts, options or collars to hedge its exposure to petroleum and natural gas commodity prices and may enter into foreign exchange forward contracts to hedge anticipated U.S. dollar denominated petroleum and natural gas sales. The derivative financial instruments are initiated within the guidelines of the Trust's risk management policy and the Trust does not enter into derivative financial instruments for trading or speculative purposes.

The Trust designates its derivative financial instruments as hedges and performs the necessary procedures to enable the use of hedge accounting. This includes the formal documentation of the hedge, linking all derivatives to specific assets and liabilities on the balance sheet or specific firm commitments or forecasted transactions and performing assessments of hedge effectiveness. Derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

Financial instruments that do not qualify for hedge accounting or are not designated as hedges are recorded at their fair value on the balance sheet with changes in the fair value recognized in earnings.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

Income Taxes

The Trust follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made for the Trust. The future income tax liability in the consolidated balance sheet represents the future income tax liability of the Trust's subsidiary.

Unit Based Compensation

The Trust has established a Performance Unit Incentive Plan (the "Plan") for employees and directors of the Trust or its subsidiary. The Trust uses the fair value method for valuing unit based compensation and unit option grants. Under this method, compensation cost attributable to performance units granted is measured at the fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the settlement of the Plan, the previously recognized value in contributed surplus will be recorded as an increase to unitholders' capital.

The Trust has not incorporated an estimated forfeiture rate for performance units that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

Per Unit Information

Per unit information is calculated on the basis of the weighted average number of trust units outstanding during the fiscal year. Diluted per unit information includes the impact of the issuable exchangeable shares, as well as, the potential dilution that could occur if securities or other contracts to issue units were exercised or converted to units. Diluted per unit information is calculated using the treasury stock method that assumes any proceeds received by the Trust upon the exercise of in-the-money unit options plus the unamortized unit compensation cost would be used to buy back trust units at the average market price for the period.

Exchangeable Securities – Non-Controlling Interest

On March 8, 2005 the accounting abstract "Exchangeable Securities Issued by Subsidiaries of Income Trusts" was amended effective for financial statements issued on or after June 30, 2005. Under the amended abstract, exchangeable shares are presented as equity of the Trust only if the exchangeable shares are entitled to receive distributions of earnings economically equivalent to distributions received by units of the trust and the holders of exchangeable shares can only dispose of them by exchanging them for trust units. The exchangeable shares of the Trust's subsidiary trade on the Toronto Stock Exchange, thereby allowing holders of the exchangeable shares to dispose of them without having to exchange them for trust units and consequently, they must be classified as non-controlling interest outside of unitholders' equity.

In accordance with the transitional provisions of the abstract, the Trust has retroactively restated prior periods dating back to the Arrangement dated July 2, 2004. As a result of this change in accounting policy, the Trust has reflected a non-controlling interest on the consolidated balance sheet of $127.2 million as at December 31, 2005 and $141.1 million as at December 31, 2004. Each redemption of exchangeable shares held by previous Progress Energy Ltd. shareholders are accounted for as a step-purchase resulting in an increase to property, plant and equipment, an increase to unitholders' capital and an increase in the Trust's future income tax liability. Cash flow was not impacted by this change. The non-controlling interest activity for the years ended December 31, 2005 and 2004 is disclosed in note 8. The effect of the adoption on previously reported amounts is as presented below as increases (decreases):

Balance Sheet

	December 31, 2004
Property, plant and equipment	9,765
Future income taxes	3,367
Non-controlling interest – exchangeable shares	141,060
Unitholders' Capital	6,911
Exchangeable Shares	(133,226)
Deficit	(8,346)

Statement of Earnings

	Year Ended December 31, 2004
Depletion, depreciation and accretion	586
Future income taxes	(202)
Non-controlling interest	7,962
Net earnings	(8,346)
Net earnings per unit	
Basic	(0.02)
Diluted	(0.01)

2. ACQUISITION OF CEQUEL ENERGY INC.

On July 2, 2004, pursuant to the Arrangement, Progress Energy Ltd. and Cequel amalgamated to create the Trust and two exploration-focused companies, ProEx and Cyries. The transaction was accounted for as a business combination with Progress being deemed the acquirer of Cequel, net of the assets acquired by Cyries. The consideration offered was 0.695 of a trust unit for each Cequel share resulting in 45,911,352 trust units and exchangeable shares being issued. The value of the transaction was $646.2 million, including $1.6 million of acquisition costs. The results of Cequel have been included in these financial statements from the date of acquisition. The transaction has been allocated as follows:

Net assets acquired (1)	
Property, plant and equipment	387,276
Goodwill	405,655
Working capital deficiency	(11,079)
Bank debt	(44,473)
Asset retirement obligations	(6,670)
Future income taxes	(84,471)
Total net assets acquired	646,238
Consideration	
Trust units issued	518,272
Exchangeable shares issued	126,369
Acquisition costs	1,597
Total purchase price	646,238

(1) Pursuant to the Arrangement, assets acquired by Cyries from Cequel were accounted for prior to Progress acquiring Cequel. As a result, the acquisition of Cequel is net of the assets acquired by Cyries.

3. PLAN OF ARRANGEMENT

Under the Arrangement, Progress Energy Ltd. transferred to ProEx certain prospective natural gas weighted assets and undeveloped land. A future tax liability has been recorded as a result of transferring tax pools of $32.5 million, which were in excess of the net book value of $24.6 million. The details are as follows:

	2004
Petroleum and natural gas properties	26,377
Future income tax assets	2,768
Asset retirement obligations	(1,813)
Total assets transferred	27,332
Bank indebtedness assumed	(10,000)
Net assets transferred and reduction in retained earnings	17,332
Plan of arrangement costs, net of income tax benefit of $7,101	12,844
Total Plan of Arrangement and reduction in retained earnings	30,176

In accordance with the Arrangement, all outstanding stock options of Progress Energy Ltd. vested and Progress Energy Ltd. accepted the holders' put right thereby settling the options for cash in the amount of $21.9 million. The after tax value of the cash settlement, net of $3.0 million of contributed surplus relating to the options, resulted in a charge of $12.8 million to retained earnings. As a result, the remaining unamortized stock based compensation cost relating to options granted after 2002 of $2.5 million was charged to earnings. The Trust also incurred $0.8 million of severance costs, which together with the stock based compensation expense, have been included in plan of arrangement expense on the consolidated statement of earnings.

4. PROPERTY, PLANT AND EQUIPMENT

	2005	2004
		(Restated)
Property, plant and equipment	**865,173**	752,846
Conversion of exchangeable shares	**32,553**	10,351
Accumulated depletion and depreciation	**(210,410)**	(119,817)
Property, plant and equipment, net	**687,316**	643,380

As described in notes 1 and 8, the redemption of exchangeable shares held by previous Progress Energy Ltd. shareholders are accounted for as a step-purchase. Consequently a charge of $22.2 million was made to property, plant and equipment for the year ended December 31, 2005 (2004 – $10.4 million).

The calculation of 2005 depletion and depreciation included an estimated $26.9 million (2004 – $18.1 million) for future development costs associated with proved undeveloped reserves and excluded $24.0 million (2004 – $22.8 million) for the estimated future net realizable value of production equipment and facilities and $65.7 million (2004 – $71.6 million) for the estimated value of unproven properties. Depletion and depreciation expense for the year ended December 31, 2005 was $90.6 million (2004 – $58.1 million).

Included in the Trust's property, plant and equipment balance is $12.5 million, net of accumulated depletion, related to asset retirement obligations ($18.7 million before accumulated depletion) (Refer to note 7).

The Trust capitalized approximately $1.4 million of geological and geophysical expenses associated with the exploration and development of capital assets during the year ended December 31, 2005 (2004 – $1.5 million).

The Trust performed a ceiling test calculation at December 31, 2005 resulting in the undiscounted cash flows from proved reserves and the lower of cost and market of unproved properties exceeding the carrying value of oil and gas assets. The following table summarizes the future benchmark prices the Trust used in the ceiling test:

	Crude Oil		Natural Gas
	West Texas Intermediate	Edmonton Par Price	AECO Gas Price
	(Cdn$/bbl) (1)	*(Cdn$/bbl)*	*(Cdn$/mmbtu)*
2006	67.06	66.25	10.60
2007	64.71	64.00	9.25
2008	60.00	59.25	8.00
2009	56.47	55.75	7.50
2010	54.71	54.00	7.20
2011–2016 (2)	54.75	54.00	7.17
Thereafter (3)	2.0%	2.0%	2.0%

(1) Future prices incorporated a $0.85 US/Cdn exchange rate.

(2) Prices shown are the average over the period.

(3) Percentage change of 2.0% represents the change in future prices each year after 2016 to the end of the reserve life.

5. BANK DEBT

	2005	2004
Direct advances	**1,326**	1,222
Banker's acceptances	**70,000**	132,500
Total bank debt	**71,326**	133,722

The Trust's credit facilities totaling $215 million are with a syndicate of banks consisting of a $200 million extendible revolving term credit facility and a $15 million working capital credit facility. The facilities are available on a revolving basis for a period of at least 364 days until May 30, 2006, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following

the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. Various borrowing options are available under the facilities including prime rate based advances and banker's acceptance loans. Average cost of borrowing under these facilities for the year ended December 31, 2005 was 4.2 percent (2004 – 3.5 percent). The credit facilities are secured by a $500 million fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress in respect of the Trust's obligations. The $215 million borrowing base is subject to semi-annual review by the banks.

6. CONVERTIBLE DEBENTURES

On February 2, 2005 the Trust issued $100 million principal amount of 6.75 percent convertible unsecured subordinated debentures (the "Debentures") for net proceeds of $95.5 million. The Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $15.00 per trust unit. The Debentures mature on June 30, 2010 at which time they are due and payable. The Trust may elect to satisfy the interest and principal obligations of the Debentures by the issuance of trust units. The net proceeds were used to reduce outstanding bank indebtedness.

The Debentures have been classified as debt net of the fair value of the conversion feature at the date of issue which has been classified as part of unitholders' equity and net of issue costs. Issue costs will be amortized over the term of the Debentures and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed within interest and financing expense on the consolidated statements of earnings. If Debentures are converted to units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the conversion price paid. The following table sets forth a reconciliation of the Debenture activity:

	Year Ended December 31, 2005
Debt portion on February 2, 2005	90,541
Accretion	793
Amortization of issue costs	755
Conversions to trust units	(12,708)
Debt portion, end of year	79,381
Equity portion on February 2, 2005	4,944
Conversions to trust units	(683)
Equity portion, end of year	4,261
Total debentures, end of year	83,642

Total interest charged to earnings for the year ended December 31, 2005 was $7.6 million which includes $0.8 million of debenture accretion and $0.8 million of amortized issue costs.

7. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligations is approximately $51.0 million which will be incurred over the next 43 years with the majority of costs incurred between 2009 and 2020. A credit adjusted risk-free rate of eight percent was used to calculate the fair value of the asset retirement obligations. In 2005 the Trust increased the inflation rate used to calculate the obligations from 1.5 percent to 2.0 percent and revised its estimate for abandonment and reclamation costs in certain areas. The impact of these revised estimates was an increase to the liability of $1.7 million.

The following reconciles the Trust's asset retirement obligations:

	2005	2004
Balance, beginning of year	**16,065**	11,778
Liabilities incurred	**2,651**	703
Liabilities settled	**(944)**	(358)
Acquisitions *(Note 2)*	**–**	6,670
Dispositions	**–**	(3,811)
Change in estimates	**1,687**	–
Accretion expense	**1,447**	1,083
Balance, end of year	**20,906**	16,065

8. NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

The Trust retroactively applied the amended accounting abstract "Exchangeable Securities issued by a Subsidiary of an Income Trust" whereby the exchangeable shares issued by the Trust's subsidiary must be reflected as non-controlling interest on the consolidated balance sheet and in turn, net earnings must be reduced by the amount of net earnings attributed to the non-controlling interest.

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares issued to Progress Energy Ltd. shareholders, the fair value of exchangeable shares issued to Cequel shareholders at the time of the Arrangement, the net earnings attributable to the exchangeable shares, less exchangeable shares (and related cumulative earnings) redeemed. The non-controlling interest charge on the consolidated statement of earnings represents the share of net earnings attributable to the exchangeable shares based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end.

The activity for non-controlling interest for the year ended December 31, 2005 and 2004 is as follows:

	2005		2004	
	Number	**Amount**	Number	Amount
			(Restated)	
Balance, beginning of year	**14,533,506**	**141,060**	–	–
Issued for common shares	–	**–**	6,999,994	20,300
Issued on Cequel acquisition *(Note 2)*	–	**–**	9,000,000	126,369
Exchanged for trust units	**(3,144,755)**	**(31,816)**	(1,466,488)	(13,571)
Non-controlling interest expense		**17,961**		7,962
Balance, end of year	**11,388,751**	**127,205**	14,533,506	141,060

The exchangeable shares can be converted, at the option of the holder, into trust units at any time and are listed on the Toronto Stock Exchange under the symbol PGE. If the number of exchangeable shares outstanding is less than 1,600,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchange ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for cash distributions.

Retraction of Exchangeable Shares

Exchangeable shareholders may redeem their shares at any time by delivering their share certificates to the Trustee, together with a properly completed retraction request. The retraction price will be satisfied with trust units equal to the amount determined by multiplying the exchange ratio on the last business day prior to the retraction date by the number of exchangeable shares redeemed.

Redemption of Exchangeable Shares

On July 2, 2009 the exchangeable shares will be redeemed by the Trust unless the Board of Directors of Progress Energy Ltd. elect to extend the redemption period. The exchangeable shares will be redeemed by either issuing units or payment in cash for an amount equivalent to the value of the exchangeable shares at the current exchange ratio.

9. UNITHOLDERS' CAPITAL

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges.

Trust Units

	2005		2004	
	Number	**Amount**	Number	Amount
			(Restated)	
Trust Units				
Balance, beginning of year	**66,898,498**	**621,490**		–
Issued for common shares	–	–	28,238,061	81,869
Issued on Cequel acquisition *(Note 2)*	–	–	36,911,352	518,272
Issued for cash	–	–	250,003	2,993
Exchangeable shares converted	**3,482,575**	**46,382**	1,499,082	20,354
Issued on conversion of convertible debentures	**921,192**	**13,391**	–	–
Unit issue costs		–		(1,998)
Balance, end of year	**71,302,265**	**681,263**	66,898,498	621,490

Redemption Right

Unitholders may redeem their trust units for cash at any time, up to a maximum of $250,000 in any calendar month, by delivering their unit certificates to the Trustee, together with a properly completed notice requesting redemption. The redemption amount per trust unit will be the lesser of 90 percent of the simple average closing price of the trust units on the principal market on which they are traded for the 10 day trading period after the trust units have been validly tendered for the redemption and the closing market price of the trust units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or if there was no trade of the trust units on that date, the average of the last bid and ask prices of the trust units on that date.

Net Earnings Per Unit

The following table summarizes the weighted average trust units used in calculating net earnings per unit:

	2005	2004
		(Restated)
Weighted average trust units – basic	**69,117,770**	49,832,041
Trust units issuable on conversion of exchangeable shares (1)	**14,934,133**	8,023,195
Performance units	**151,561**	2,526
Stock options	–	677,739
Warrants	–	462,753
Weighted average trust units – diluted	**84,203,464**	58,998,254

(1) Calculated based on the weighted average exchangeable shares outstanding during the year at the year end exchange ratio.

An adjustment to the numerator of $18.0 million for the year ended December 31, 2005 (2004 – $8.0 million) is required in the diluted earnings per unit calculation to provide for earnings attributable to non-controlling interest. Units potentially issuable on the conversion of the Debentures are anti-dilutive and are not included in the calculation of diluted weighted average units for the year ended December 31, 2005.

Performance Unit Incentive Plan

In conjunction with the Arrangement, the Trust established a Performance Unit Incentive Plan (the "Plan") for employees and directors of the Trust or its subsidiary. The number of units reserved for issuance under the Plan shall not exceed 5 percent of the aggregate number of issued and outstanding units of the Trust and including the number of units which may be issued on the exchange of the outstanding exchangeable shares, which may be converted into trust units. Under the Plan, performance units shall be granted by the Board of Directors of Progress Energy Ltd. from time to time at its sole discretion. The performance units will vest on the third anniversary of the date of grant and actual payment will be determined based on the performance of the Trust relative to its peers. Performance factors range from 0.5 to 1.5 times the initial performance units granted. Over the three year term the performance units will attract distributions. The Trust expects to pay out the distribution portion in cash while the units earned will be issued from treasury.

The Board of Directors of Progress Energy Ltd. granted 395,267 performance units effective July 2, 2004. As a result, the fair value of the performance units granted, calculated using a performance factor of 1.0, was approximately $5.3 million of which $4.7 million will be amortized through unit based compensation expense and $0.6 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

The Board of Directors of Progress Energy Ltd. granted 512,500 performance units effective July 2, 2005. The fair value of the performance units using a performance factor of 1.0 was approximately $8.0 million of which $6.9 million will be amortized through unit based compensation expense and $1.1 million will be capitalized over the vesting period with a corresponding increase to contributed surplus.

For the year ended December 31, 2005 $3.0 million (2004 – $0.5 million) was charged to unit based compensation expense and $0.3 million (2004 – nil) was capitalized relating to the total performance units outstanding.

Contributed Surplus

The following table reconciles the Trust's contributed surplus:

	2005	2004
Balance, beginning of year	**171**	246
Unit based compensation expense	**3,029**	2,889
Unit based compensation capitalized	**330**	–
Options exercised	–	(10)
Options settled for cash	–	(2,954)
Balance, end of year	**3,530**	171

10. FUTURE INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. Cash distributions for the year ended December 31, 2005 totaled $116.5 million, reducing the Trust's expected future income tax expense for the year.

During 2005, income tax audits were performed on the 2002 and 2003 tax returns of Cequel and Progress Energy Ltd. As a result of these audits, the provision for future income tax expense includes a charge of $3.5 million due to tax pool adjustments.

The combined provision for taxes in the consolidated statements of earnings and deficit reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

	2005	2004
		(Restated)
Earnings before taxes	**113,124**	49,226
Statutory income tax rate	**37.9%**	40.1%
Expected income taxes	**42,874**	19,739
Add (deduct)		
Net income of the Trust	**(43,366)**	(22,337)
Non-deductible crown charges	**20,271**	13,365
Resource allowance	**(17,083)**	(9,337)
Reduction in federal and provincial income tax rates	**(2,003)**	(2,452)
Income tax audit adjustments	**3,495**	–
Attributed Canadian Royalty Income	**(886)**	(1,945)
Other	**765**	(1,454)
	4,067	(4,421)

The future income taxes liability at December 31 is comprised of the tax effect of temporary differences as follows:

	2005	2004
		(Restated)
Property, plant and equipment	**135,120**	123,578
Asset retirement obligations	**(7,060)**	(5,539)
Commodity sales contracts	**(488)**	(722)
Share issue costs	**(629)**	(1,216)
Attributed Canadian Royalty Income	**(2,757)**	(3,618)
	124,186	112,483

As at December 31, 2005, the Trust's corporate subsidiary, Progress Energy Ltd., has tax pools of approximately $225.0 million (2004 – $201.0 million) available for deduction against future taxable income.

11. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in Non-cash Working Capital

	2005	2004
Accounts receivable	**(15,007)**	6,920
Prepaid expenses and deposits	**(774)**	56
Accounts payables	**1,924**	7,078
Current income taxes payable	**(1,708)**	1,209
Change in non-cash working capital	**(15,565)**	15,263
Relating to:		
Financing activities	**–**	(268)
Investing activities	**(679)**	(6,440)
Operating activities	**(14,886)**	21,971

Interest and Taxes Paid

	2005	2004
Interest paid	**6,220**	3,725
Income and other taxes paid	**3,366**	573

12. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The Trust's financial instruments recognized in the balance sheet consist of accounts receivable, accounts payable and accrued liabilities, bank debt and convertible debentures. The fair value of these financial instruments, excluding the convertible debentures, approximate their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank debt. The fair value of the convertible debentures outstanding as at December 31, 2005 was approximately $96.2 million.

Credit Risk

The Trust's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. The Trust routinely assesses the financial strength of its customers.

The Trust may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. The Trust mitigates this risk by entering into transactions with highly rated major financial institutions.

Commodity Price Contracts

The Trust has entered into several derivative financial instruments for the purpose of protecting its cash flow from operations from the volatility of natural gas commodity prices. A natural gas collar was acquired in the Cequel acquisition valued at $1.7 million at June 30, 2004 and capitalized as part of the acquisition. Subsequent to the acquisition $1.7 million was charged to earnings in 2004 for this collar.

Contracts outstanding in respect to financial instruments are as follows:

Contract Natural Gas	Volume	Pricing Point	Strike Price *($gj)*	Cost/ Premium	Term
Natural Gas					
Costless collar (1)	5,000 gj/d	AECO	Cdn$7.50 – Cdn$9.80	n/a	Nov 01/05 – Mar 31/06
Costless collar (1)	5,000 gj/d	AECO	Cdn$7.50 – Cdn$9.75	n/a	Nov 01/05 – Mar 31/06
Costless collar (1)	5,000 gj/d	AECO	Cdn$7.75 – Cdn$9.50	n/a	Nov 01/05 – Mar 31/06
Costless collar (1)	5,000 gj/d	AECO	Cdn$8.00 – Cdn$9.55	n/a	Nov 01/05 – Mar 31/06
Costless collar (1)	5,000 gj/d	AECO	Cdn$8.35 – Cdn$9.75	n/a	Nov 01/05 – Mar 31/06
Costless collar (1)	5,000 gj/d	AECO	Cdn$8.30 – Cdn$9.85	n/a	Nov 01/05 – Mar 31/06
Call spread (1)	5,000 gj/d	AECO	Cdn$10.55 – Cdn$11.55	$0.38/gj	April 01/06 – Oct 31/06
Call spread (1)	5,000 gj/d	AECO	Cdn$10.74 – Cdn$11.74	$0.38/gj	April 01/06 – Oct 31/06
Call spread (1)	5,000 gj/d	AECO	Cdn$10.75 – Cdn$11.75	$0.38/gj	April 01/06 – Oct 31/06
Call spread (1)	5,000 gj/d	AECO	Cdn$10.68 – Cdn$11.68	$0.38/gj	April 01/06 – Oct 31/06
Call spread (1) (2)	5,000 gj/d	AECO	Cdn$7.22 – Cdn$8.22	$0.36/gj	April 01/06 – Oct 31/06
Call spread (1) (2)	10,000 gj/d	AECO	Cdn$7.20 – Cdn$8.20	$0.32/gj	April 01/06 – Oct 31/06
Call spread (1) (2)	5,000 gj/d	AECO	Cdn$7.10 – Cdn$8.10	$0.30/gj	April 01/06 – Oct 31/06

(1) Costless collar and call spread strike prices indicate minimum floor and maximum ceiling

(2) Contract entered into subsequent to December 31, 2005

The estimated fair value of the natural gas financial instruments that qualify for hedge accounting was a gain of $0.3 million as at December 31, 2005 and represents the amount the Trust would receive to terminate the contracts at December 31, 2005. These instruments have no carrying value recorded in the financial statements.

Physical Gas Sales Contracts

The Trust also enters into physical gas sales contracts from time to time under its risk management policy for the purpose of protecting its cash flow from operations before changes in non-cash working capital from the volatility of natural gas prices.

Contracts outstanding in respect to physical gas sales contracts were as follows:

Contract Natural Gas	Volume	Pricing Point	Strike Price *($gj)*	Cost/ Premium	Term
Natural Gas					
Costless collar	5,000 gj/d	AECO	Cdn$7.55 – Cdn$9.85	n/a	Nov 01/05 – Mar 31/06
Costless collar	5,000 gj/d	AECO	Cdn$8.00 – Cdn$9.55	n/a	Nov 01/05 – Mar 31/06

Commodity Sales Contract

The following physical gas sales contract was outstanding at December 31, 2005. This contract was acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002, at which time the fair value of the contracts was a liability of $4.1 million. This value was recorded as a liability on June 3, 2002, and is being amortized over the life of the contract. At December 31, 2005 the unamortized liability remaining was $1.4 million.

Volume	Pricing Point	Progress Price	Term
1,000 gj/d	AECO	$2.11/gj in 2006 escalating at 2.5% annually	Jun 1/97 – Oct 31/08

13. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation contracts, drilling rig agreements and office space. Payments required under these commitments for each of the next five years are: 2006 – $11.1 million; 2007 – $11.6 million; 2008 – $9.0 million; 2009 – $7.2 million; 2010 – $4.7 million; and thereafter $3.3 million.

2005 SELECTED QUARTERLY INFORMATION

FINANCIAL HIGHLIGHTS

($ thousands, except per unit amounts)	Three Months Ended 2005 March 31	June 30	Sept. 30	Dec. 31	Annual 2005
Income Statement					
Petroleum and natural gas revenue	79,007	83,222	93,372	114,167	**369,768**
Cash flow (1)	42,511	44,466	53,215	65,785	**205,977**
Per unit – diluted	0.52	0.53	0.63	0.77	**2.45**
Cash distributions declared	28,574	28,874	29,210	29,802	**116,460**
Per unit	0.42	0.42	0.42	0.42	**1.68**
Net earnings	17,527	16,840	25,159	29,398	**88,924**
Per unit – basic	0.27	0.25	0.36	0.41	**1.29**
Per unit – diluted	0.27	0.24	0.36	0.40	**1.27**
Payout Ratio					
Excluding exchangeable shares	67%	65%	55%	45%	**57%**
Including exchangeable shares	81%	79%	66%	54%	**69%**
Balance Sheet					
Capital Expenditures	34,380	13,559	24,492	35,227	**107,658**
Total debt	187,312	185,708	186,115	173,580	**173,580**
Unitholders' equity	632,700	623,308	635,630	654,648	**654,648**
Trust Units *(thousands, except where otherwise stated)*					
Units outstanding, end of period	68,646	68,820	69,956	71,302	**71,302**
Units issuable for exchangeable shares	13,992	14,281	13,601	13,482	**13,482**
Total units outstanding and issuable for exchangeable shares, end of period	82,638	83,101	83,557	84,784	**84,784**
Weighted average units – diluted (2)	82,485	83,176	83,700	84,675	**84,203**
Exchange ratio, end of period	1.08438	1.12038	1.15421	1.18384	**1.18384**
Trust Unit Trading Statistics *($)*					
High	14.50	13.79	17.82	17.85	**17.85**
Low	12.52	11.90	13.07	14.08	**11.90**
Closing	13.38	13.03	17.61	17.17	**17.17**
Unit volume traded *(thousands)*	17,788	11,544	19,159	18,385	**66,876**
Exchangeable Shares Trading Statistics *($)*					
High	15.85	15.50	20.62	20.36	**20.62**
Low	13.96	13.27	15.00	16.61	**13.27**
Closing	14.60	14.96	19.26	20.36	**20.36**
Share volume traded *(thousands)*	1,460	290	613	52	**2,415**

(1) See discussion in the Management Discussion and Analysis.

(2) Includes exchangeable shares converted at the end of period exchange ratio.

2005 SELECTED QUARTERLY INFORMATION

OPERATIONAL HIGHLIGHTS

	Three Months Ended 2005				Annual
	March 31	June 30	Sept. 30	Dec. 31	**2005**
Daily Production					
Natural gas *(mcf/d)*	84,523	79,236	80,804	85,173	**82,431**
Crude oil *(bbls/d)*	2,550	3,067	2,734	2,762	**2,779**
Natural gas liquids *(bbls/d)*	1,598	1,305	1,280	1,355	**1,384**
Total daily production *(boe/d)*	18,235	17,578	17,481	18,312	**17,901**
Average Realized Prices					
Natural gas – before hedging *($/mcf)*	7.31	8.12	9.33	12.18	**9.27**
Natural gas – after hedging *($/mcf)*	7.69	8.13	9.11	11.38	**9.11**
Crude oil *($/bbl)*	59.44	64.20	72.66	67.22	**65.98**
Natural gas liquids *($/bbl)*	47.82	56.41	62.68	63.63	**57.20**
Highlights *($/boe)*					
Weighted average sales price	48.14	52.02	58.06	67.77	**56.59**
Royalties	11.78	13.16	14.39	18.38	**14.46**
Operating expenses	5.69	5.72	5.70	5.66	**5.69**
Transportation expenses	1.89	1.98	1.95	1.89	**1.93**
Operating Netbacks	28.78	31.16	36.02	41.84	**34.51**
General and administrative expense	1.23	1.33	0.83	0.75	**1.03**
Unit based compensation	0.31	0.32	0.62	0.59	**0.46**
Interest and financing expenses	1.26	1.80	1.80	1.62	**1.62**
Depletion, depreciation and accretion	14.05	14.19	14.26	13.86	**14.09**
Net earnings before taxes	11.93	13.52	18.51	25.02	**17.31**
Capital taxes	0.33	0.34	0.34	0.32	**0.33**
Future income taxes (recovery)	(1.48)	0.55	(0.63)	3.93	**0.62**
Non-controlling interest – exchangeable shares	2.40	2.10	3.16	3.32	**2.75**
Net Earnings	10.68	10.53	15.64	17.45	**13.61**
Drilling Results					
Gross	25	8	24	31	**88**
Net – natural gas	8.4	2.7	9.7	16.0	**36.8**
Net – crude oil	2.6	0.0	1.9	1.7	**6.2**
Success Rate *(percent)*	86	60	89	100	**90**

2004 SELECTED QUARTERLY INFORMATION

FINANCIAL HIGHLIGHTS

	Three Months Ended 2004				Annual
($ thousands, except per unit amounts)	March 31	June 30	Sept. 30	Dec. 31	2004
Income Statement					
Petroleum and natural gas revenue	30,812	38,811	68,299	76,767	214,689
Cash flow (1)	14,928	17,833	36,355	41,344	110,460
Per unit – diluted	0.41	0.49	0.45	0.50	1.87
Cash distributions declared			27,670	28,035	55,705
Per unit			0.42	0.42	0.84
Net earnings	6,247	4,464	15,324	18,196	44,231
Per unit – basic	0.19	0.13	0.24	0.28	0.89
Per unit – diluted	0.17	0.12	0.24	0.28	0.88
Payout Ratio					
Excluding exchangeable shares			76%	68%	
Including exchangeable shares			94%	83%	
Balance Sheet					
Capital Expenditures	43,702	16,615	12,112	33,993	106,422
Total debt	82,252	106,061	151,580	171,543	171,543
Unitholders' equity	140,224	134,816	614,554	614,791	614,791
Trust Units *(thousands, except where otherwise stated)*					
Units outstanding, end of period	33,939	35,238	66,164	66,898	66,898
Units issuable for exchangeable shares			15,575	15,291	15,291
Total units outstanding and issuable for exchangeable shares, end of period	33,761	34,156	81,739	82,189	82,189
Weighted average units (2)			81,016	81,979	58,998
Exchange ratio, end of period			1.02188	1.05215	1.05215
Trust Unit Trading Statistics *($)*					
High			15.09	15.81	15.81
Low			12.12	12.95	12.12
Closing			14.95	13.52	13.52
Unit volume traded *(thousands)*			46,567	18,774	65,341
Exchangeable Shares Trading Statistics *($)*					
High			15.25	16.00	16.00
Low			13.00	13.55	13.00
Closing			15.25	14.11	14.11
Share volume traded *(thousands)*			272	95	367

(1) See discussion in the Management Discussion and Analysis.

(2) Includes exchangeable shares converted at the end of period exchange ratio.

2004 SELECTED QUARTERLY INFORMATION

OPERATIONAL HIGHLIGHTS

	Three Months Ended 2004				Annual
	March 31	June 30	Sept. 30	Dec. 31	2004
Daily Production					
Natural gas *(mcf/d)*	34,805	44,809	81,783	86,998	62,221
Crude oil *(bbls/d)*	2,227	2,160	2,475	2,475	2,335
Natural gas liquids *(bbls/d)*	329	325	1,197	1,394	814
Total daily production *(boe/d)*	8,357	9,953	17,302	18,368	13,519
Average Realized Prices					
Natural gas – before hedging *($/mcf)*	6.66	7.17	6.94	7.32	7.08
Natural gas – after hedging *($/mcf)*	6.63	7.16	6.99	7.45	7.13
Crude oil – before hedging *($/bbl)*	44.15	48.75	53.35	55.69	50.72
Crude oil – after hedging *($/bbl)*	43.12	42.47	47.31	48.21	45.44
Natural gas liquids *($/bbl)*	36.33	43.40	45.09	48.24	45.40
Highlights *($/boe)*					
Weighted average sales price	40.52	42.85	42.91	45.42	43.39
Royalties	9.39	10.99	10.52	11.58	10.80
Operating expenses	6.36	6.15	5.81	5.55	5.87
Transportation expenses	2.99	2.98	1.98	1.96	2.31
Operating Netbacks	21.78	22.73	24.60	26.33	24.41
General and administrative expense	1.29	0.69	1.22	1.14	1.04
Unit based compensation	–	–	–	0.10	0.10
Interest and financing expenses	0.66	0.69	0.70	0.69	0.69
Depletion, depreciation and accretion	8.97	9.47	13.09	13.57	11.96
Plan of arrangement expenses	–	3.69	–	–	0.67
Net earnings before taxes	10.86	8.19	9.59	10.83	9.95
Capital taxes	0.24	0.20	0.35	0.31	0.29
Future income taxes (recovery)	2.41	3.06	(2.72)	(2.77)	(0.89)
Non-controlling interest – exchangeable shares			2.33	2.52	1.61
Net Earnings	8.21	4.93	9.63	10.77	8.94

Drilling Results					
Gross	28	5	10	21	64
Net – natural gas	14.9	2.5	6.2	6.9	30.5
Net – crude oil	2.4	2.0	0.0	2.6	7.0
Success Rate *(percent)*	79	83	100	100	89

CORPORATE INFORMATION

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President & CEO
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Michael R. Culbert
President and CEO
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Gary E. Perron (1) (3)
Senior Vice President and Managing Director
BMO Nesbitt Burns
Calgary, Alberta

(1) Member of Audit Committee
(2) Member of Reserve Committee
(3) Member of Compensation Committee
(4) Member of Technical Services Committee
(5) Member of Corporate Governance and Nominating Committee

Environment, Health and Safety matters are addressed by the entire Board of Directors.

OFFICERS

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Chairman

Michael R. Culbert
President and CEO

Steven A. Allaire
Senior Vice President

Greg W. Kist
Vice President, Investor Relations and Marketing

Art A. MacNichol
Vice President, Finance & Chief Financial Officer

Cindy R. Rutherford
Vice President, Land

Neil H. Samis
Vice President, Production

Daniel C. Topolinsky
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TRUSTEE AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta

STOCK EXCHANGE

The Toronto Stock Exchange

Trading Symbols:
Trust Units – PGX.UN
Exchangeable Shares – PGE
Convertible Debentures – PGX.DB

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2005 Annual Report

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